ANALYSIS OF FIELD DEVELOPMENT STRATEGIES OF CO_2 EOR/CAPTURE PROJECTS USING A RESERVOIR SIMULATION ECONOMIC MODEL

A Thesis

by

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ABSTRACT

A model for the evaluation of CO_2-EOR projects has been developed. This model includes both reservoir simulation to handle reservoir properties, fluid flow and injection and production schedules, and a numerical economic model that generates a monthly cash flow stream from the outputs of the reservoir model. This model is general enough to be used with any project and provide a solid common basis to all of them.

This model was used to evaluate CO_2-EOR injection and production strategies and develop an optimization workflow. Producer constraints (maximum oil and gas production rates) should be optimized first to generate a reference case. Further improvements can then be obtained by optimizing the injection starting date and the injection plateau rate.

Investigation of sensitivity of CO_2-EOR to the presence of an aquifer showed that CO_2 injection can limit water influx in the reservoir and is beneficial to recovery, even with a strong water drive. The influence of some key parameters was evaluated: the producer should be completed in the top part of the reservoir, while the injector should be completed over the entire thickness; it is recommended but not mandatory that the injection should start as early as possible to allow for lower water cut limit.

Finally, the sensitivity of the economics of the projects to some key parameters was evaluated. The most influent parameter is by far the oil price, but other parameters such

as the CO_2 source to field distance, the pipeline cost scenario, the CO_2 source type or the CO_2 market price have roughly the same influence. It is therefore possible to offset an increase of one of them by reducing another.

ACKNOWLEDGEMENTS

I would like to thank my sister Camille, my brother Bruno, and my parents Claire and Didier, who always supported my choices; I would not stand where I am without them.

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I finally want to extend my gratitude to Total, for their sponsorship throughout my joint master's degree at Texas A&M University and IFP School.

NOMENCLATURE

CapEx	Capital Expenditures
$C_{Abandonment}$	Abandonment cost for one well ($)
C_{Drill}	Drilling cost for one well ($)
$C_{Facilities}$	Facilities cost for one pattern ($)
C_{Tubing}	Tubing cost for one well ($)
$DEPTH$	Drilling depth (feet)
EIA	US Energy Information Administration
EOR	Enhanced Oil Recovery
EOS	Equation of State
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
$Index_t$	Cost index for the tubing costs in year t
LCOE	Levelized Cost of Electricity
MMP	Minimum Miscibility Pressure
Mscf	Thousand Standard Cubic Feet
mton	Metric ton
OpEx	Operating Expenditures
$OpEx_{Fixed}$	Fixed Operating Expenditures for one well
PC	Pulverized Coal

STB	Stock Tank Barrel
WTI	West Texas Intermediate

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Page

CHAPTER I

INTRODUCTION AND LITERATURE REVIEW

I.1. Energy Demand and Global Warming

Worldwide energy consumption is predicted to jump from 505 quadrillion Btu in 2008 to 770 quadrillion Btu in 2035 (EIA 2011). This increase of more than 50% will be largely based on the increase of the consumption of fossil fuels: oil for transportation, and coal and natural gas for power generation.

Meanwhile, global warming caused by the emission of greenhouse gases is likely to accelerate, impacting all countries, worldwide, in a dramatic way. Some studies suggest that global warming is already costing $1.2 trillion per year, wiping 1.6% annually from global GDP; this figure could reach 3.2% of global GDP in 2030 (DARA Group 2012).

CO_2, the main product of fossil fuel consumption, is the main greenhouse gas because it is the one emitted in by far the largest quantities. Therefore, to sustain the growth in energy demand while reducing greenhouse gases emissions, mitigation policies must be implemented.

I.2. Greenhouse Gases Mitigation Strategies

Policies are developed to reduce CO_2 emissions. The IEA (2011b)developed two of the main policy scenarios: the “New Policies” scenario, that accounts for all the policies implemented and announced; and the “450” scenario, whose target is to limit the atmospheric CO_2 concentration at 450 ppm in 2035. This scenario would yield a 50% chance of limiting global warming to 2 °C.

Based on the CO_2 abatement costs, the IEA built a model that indicates CO_2 emissions would drop from the “New Policies” to the “450” level, with the lowest possible cost (Figure 1). One of the key elements of this mitigation strategy is the implementation of Carbon Capture and Storage (CCS), whose share in reduction should increase from 3% in 2020 to 22% in 2035.

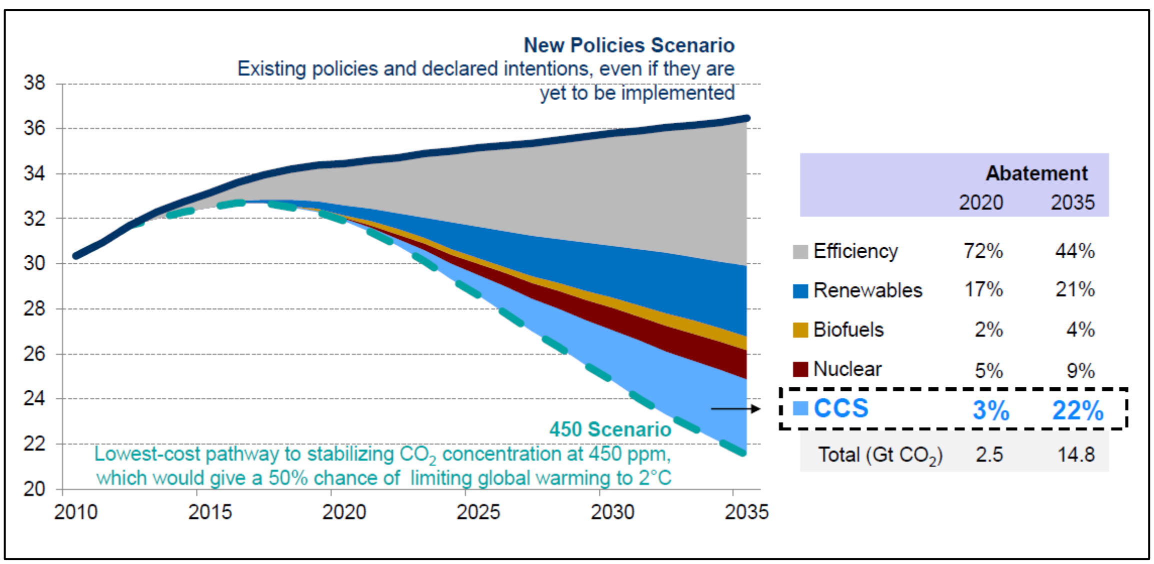

Figure 1: CO_2 abatement levers to reach the target emissions from the IEA’s 450 Scenario, relative to the New Policies Scenario (IEA 2011b)

I.3. Overview of Carbon Capture and Storage

Carbon Capture and Storage is a technology that enables CO_2 capture from large emission sources such as hydrocarbon-fueled power plants or industry sources such as cement factories. The captured CO_2 is then transported to a storage site, where it is injected in geological traps. Several options are possible (Figure 2): depleted oil and gas reservoirs, deep unmineable coal seams or deep saline aquifers, among others.

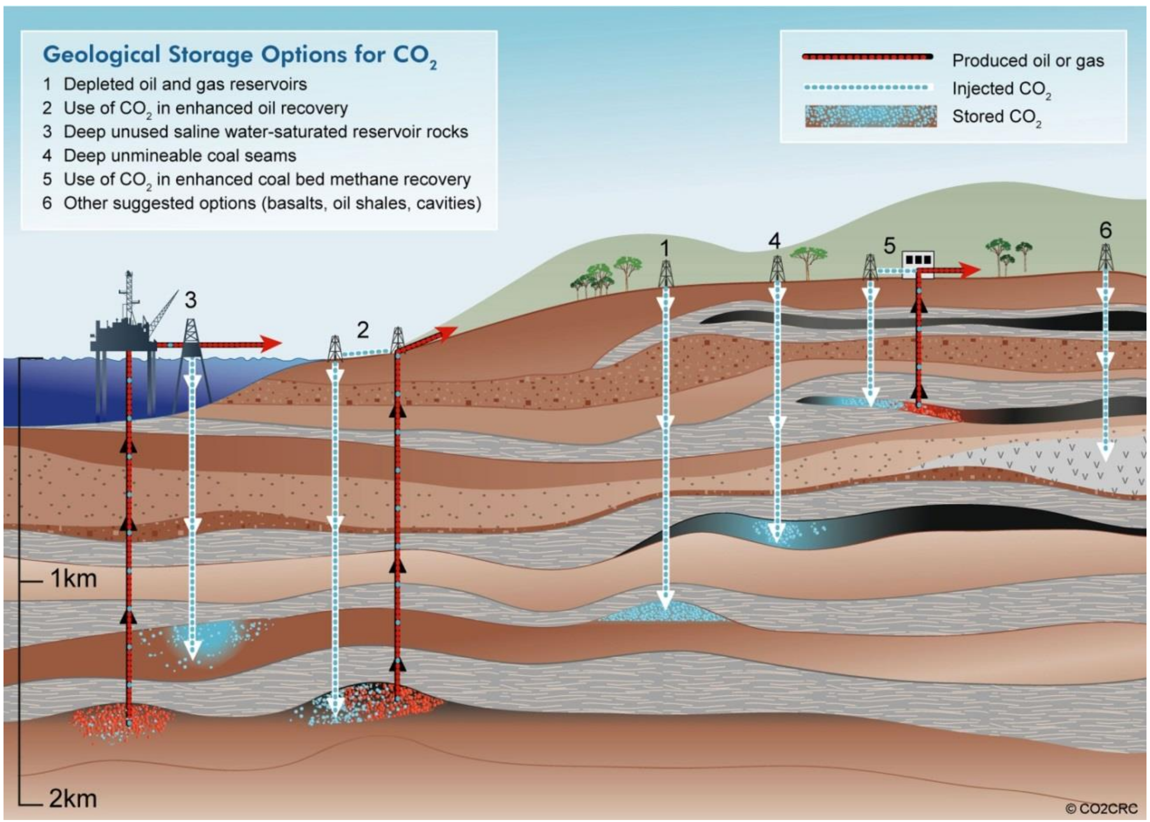

Figure 2: Geological options suitable for CO_2 storage (image courtesy of CO2CRC)

Three main issues exist with CO_2 geological storage: the transport cost; the storage capacity; and the uncertainty of the target formation properties. Each solution has advantages and drawbacks regarding these issues: depleted oil and gas reservoirs are very well characterized and offer high CO_2 storage densities, but they are not widespread (which means it is harder to find a close CO_2 source) and have smaller capacities; deep saline aquifers, on the contrary, are not well characterized and cannot provide as high storage densities, but they are extensively distributed and offer gigantic storage capacities. However, the pace of the industrial development of CCS is slow, compared to the roadmap defined by the IEA (2010) to reach the objectives of the "450" scenario. This is mostly due to the lack of economic incentives to develop CCS projects (SBC Energy Institute 2012).

I.4. Use of CO_2 in Enhanced Oil Recovery

The use of CO_2 in Enhanced Oil Recovery (CO_2-EOR) where CO_2 is ultimately stored in the reservoir is therefore an interesting alternative option, as the incremental oil production can compensate and even offset the additional expenditures required by CO_2 injection.

The miscible CO_2-EOR process is illustrated on Figure 3. The effects of the injected CO_2 are multiple: it provides pressure support; reduces the oil viscosity; and decreases the residual oil saturation. When it breaks through at the producer, it is either separated from the natural gas and re-injected, or directly re-injected with the natural gas. Ultimately, CO_2 will be trapped by residual trapping and in free phase in the pore space.

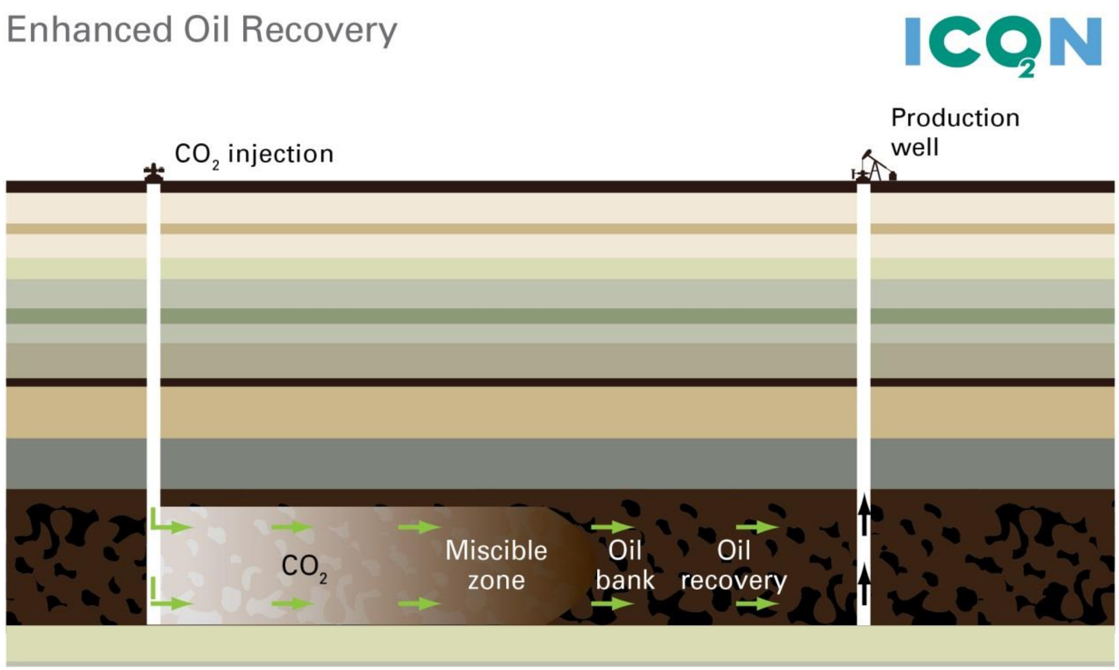

Figure 3: Overview of the miscible CO_2-EOR process (image courtesy of ICO_2N)

In CO_2-EOR, CO_2 storage is no longer the primary drive to launch the projects: as conventional oil and gas reservoirs are produced, unconventional fields are put into production, at a higher cost. CO_2-EOR is a process that has been used in the United States since the 1970s; it increases the lives of fields at competitive costs (Figure 4). However, the CO_2 used in most projects today is extracted from CO_2 domes, because it is less expensive than carbon capture from power plants.

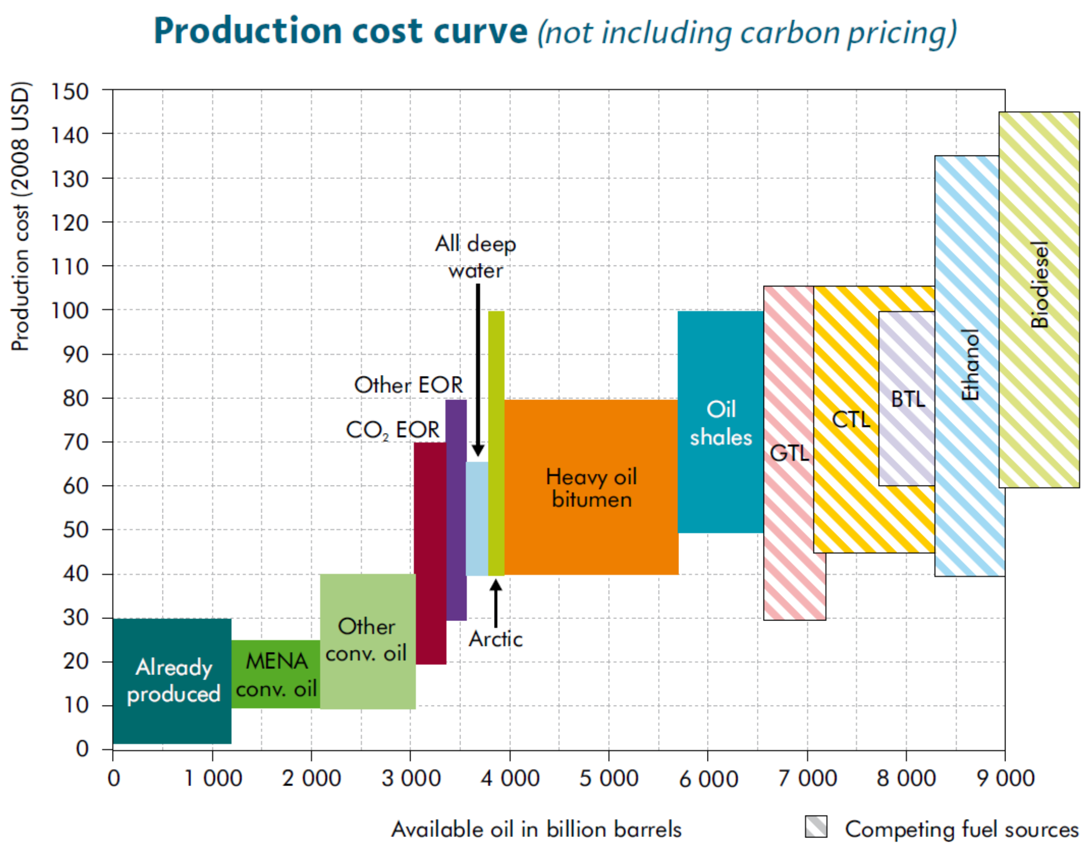

Figure 4: Production cost curve for current oil production technologies (IEA 2011a)

I.5. Objectives of the Research

Several studies have been published to evaluate strategies for CO_2-EOR (Algharaib and Abu Al-Soof 2008; Global CCS Institute 2011; Heddle et al. 2003; Hurter et al. 2007; McCollum and Ogden 2006; Nguyen 2009; Valbuena et al. 2012). Some of them focus on the economic modeling, others on the reservoir phenomena and simulation.

These studies provided important results, but their limitations are that they are not fully integrated, and therefore, do not allow the evaluation of different injection and production strategies. For instance, the economic models developed do not allow sophisticated modeling of the reservoir flows, and do not let the user specify complex schedules. Reservoir simulation-based models, on the other hand, provide very good insight of the phenomena occurring during the production, but they cannot account for the fact that, for instance, some production conditions would be unrealistic from an economic viewpoint.

The overall objective of this thesis is to build a model that will couple a reservoir simulation model with an economic model, as represented in Figure 5. The main tasks are to:

- Build an integrated model that uses reservoir simulation to handle fluid flow and an economic model; to
- Evaluate injection and production strategies using the model previously developed; and to
- Evaluate the sensitivity of CO_2-EOR projects to key parameters, such as oil price, CO_2 tax, source-field distance, or aquifer presence.

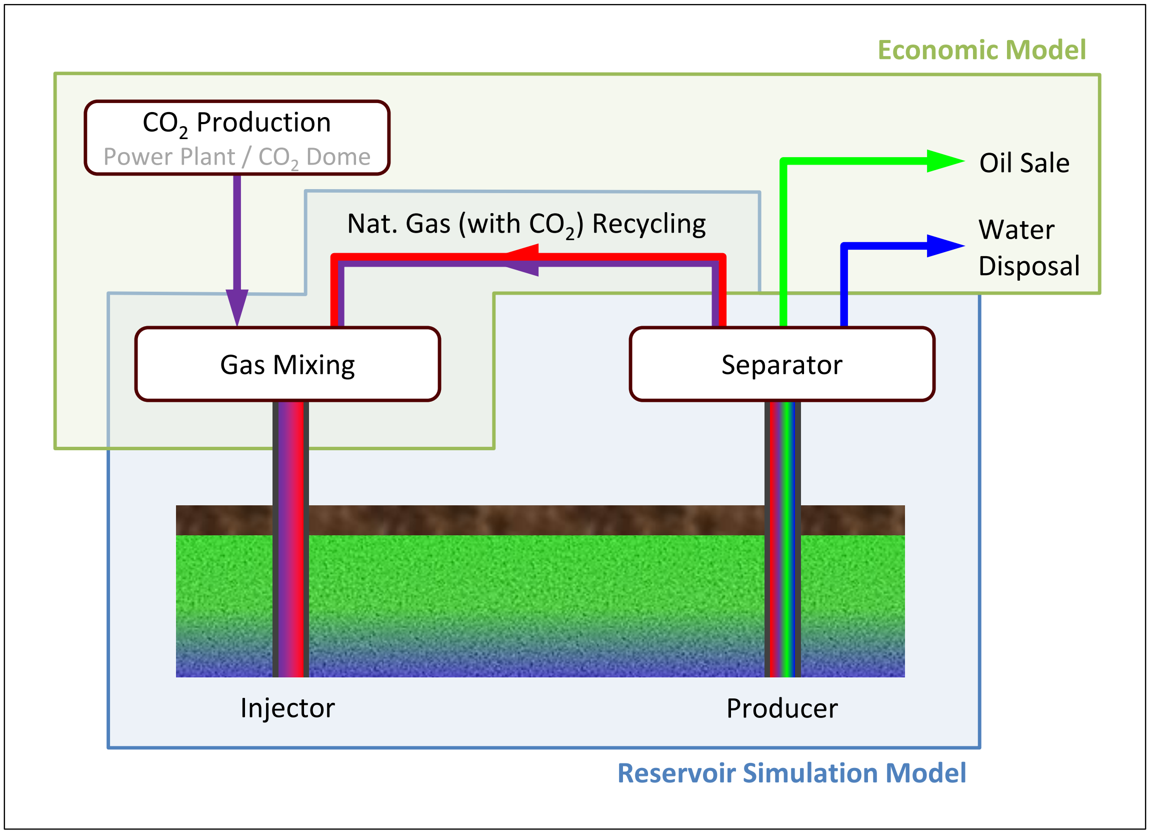

Figure 5: Overview of the coupled model

CHAPTER II

RESERVOIR MODEL OF A CO2-EOR PROJECT

The aim of this chapter is to describe the reservoir model part of the coupled model (Figure 6). The reservoir model used in this thesis is for the most part the same as the one described by Nguyen (2009). The fluid, compositional model and grid are identical. This chapter is therefore mostly based on previously published work by Nguyen (2009).

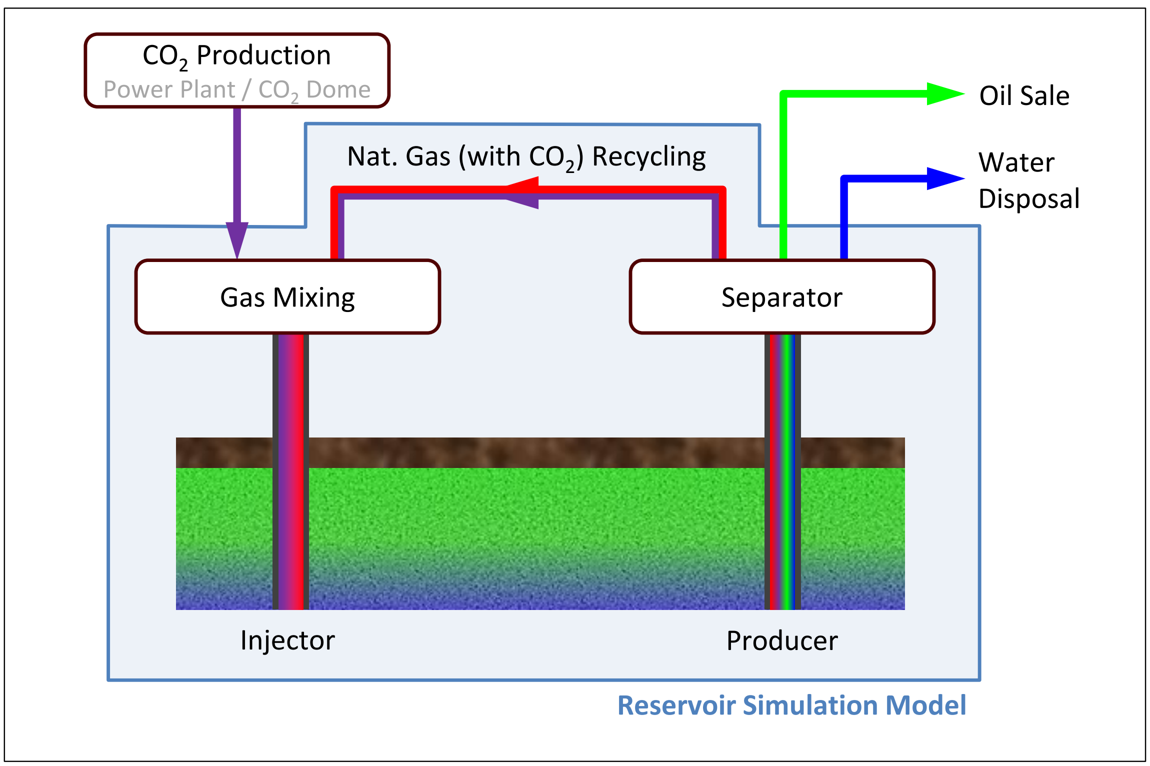

Figure 6: Scope of this chapter: definition of the reservoir model

II.1. Selected Fluid

The reservoir fluid selected is a black oil for which data are freely provided by GeoMark Research (1997), available at http://www.rfdbase.com. It is a 28.1 °API oil from the Gemini field in the Gulf of Mexico, and more specifically from the Mississippi Canyon block 291. Its RFDbase ID is CHT-LA-970901.

The reservoir temperature is 157 °F and its pressure is 6,017 psi. The oil was sampled at 11,457 ft Measured Depth. Its saturation pressure is 5,150 psia, and would give a density of 0.728 g/cc (45.45 (lb/cuft) and a viscosity of 1.151 cP. The molar composition of the oil is given in Table 1. Notice that the oil initially contains 0.061 mole% of CO_2.

Table 1: Composition of the fluid used in the model. This composition is given by the RFDbase database (GeoMark Research 1997)

Component	Composition (mole%)	
N_2	0.198	
CO_2	0.061	
H_2S	0	
C1	59.805	
C2	2.332	
C3	2.228	
iC4	0.484	
nC4	1.514	
iC5	0.721	
nC5	0.998	
C6	2.31	
C7+	29.349	
C7+ Molecular Weight	265.61	g/mole
C7+ Specific Gravity	0.902	
Reservoir Fluid Molecular Weight	93.68	g/mole

To speed up computation time, the oil components are grouped into 5 pseudo-component groups, 4 of which are hydrocarbon components, the first one being CO_2. In the model, the fluid interactions will be modeled using the four-parameter Peng-Robinson Equation of State (EOS). Using the PVTi (2008a version) software from Schlumberger to calculate the equivalent properties of the pseudo-components, Nguyen (2009) showed that the reservoir oil was well modeled using the compositional model described in Table 2. More details can be found in his thesis.

Table 2: Compositional model of the reservoir fluid

Component	ZI mole%	Pseudo-Component	ZI mole%	MW g/mol	T_c °R	P_c psi	Z_c	V_c cuft/lb	S_{Shift}
CO2	0.06	CO2	0.060	44.0	548.5	1071.3	0.27	1.51	-0.10
N2	0.2	N2C1	60.010	16.1	342.7	667.2	0.28	1.57	-0.12
C1	59.81								
C2	2.33	C2C4	6.550	43.4	592.4	578.5	0.29	3.20	-0.11
C3	2.23								
iC4	0.48								
nC4	1.51								
iC5	0.72	C5C6	4.030	78.9	1065.1	510.2	0.24	5.34	-0.04
nC5	1								
C6	2.31								
C7+	29.35	C7+	29.350	265.4	1090.0	357.9	0.50	16.30	-1.30

II.2. Reservoir Model

The reservoir model chosen is a 40-acre spacing, 5-spot well pattern, in a reservoir with no slant.

II.2.1. The Pattern

The pattern chosen is a 5-spot well pattern, which is a common one for miscible gas EOR operations (Green and Willhite 1998). Moreover, it is a convenient pattern to model since it is regular, has many axes of symmetry, and has an equal number of producers and injectors. Thanks to the axes of symmetry of the pattern that are no flow boundaries, it can be fully studied by modeling only 1/8th of the pattern (Figure 7).

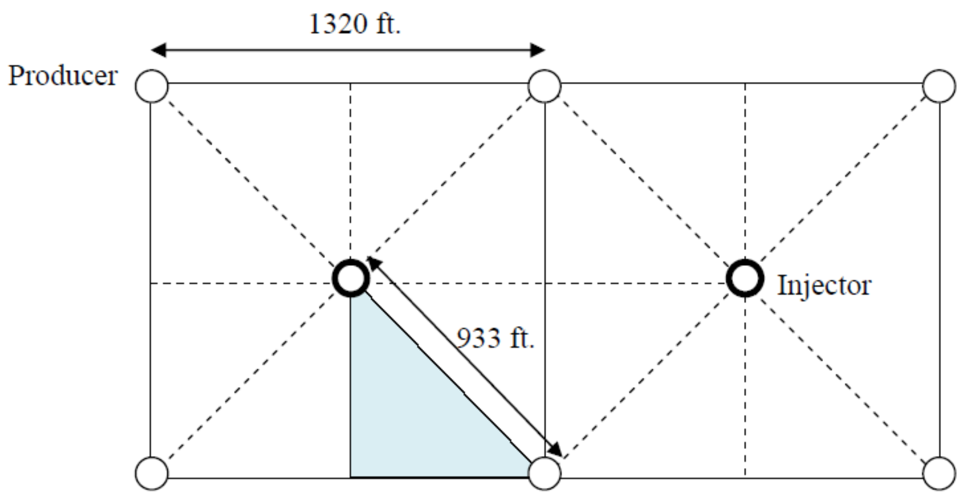

Figure 7: Model of the 5-spot pattern. The blue area is the 1/8th that will be modeled (Nguyen 2009)

Since only 1/8th of the pattern is modeled, injection and production data will be multiplied by 8 to obtain the values of the whole pattern. Therefore, if not specified otherwise, the values reported are not upscaled and correspond to 1/8th of a pattern.

The spacing chosen is a 40-acre spacing: for EOR operations, it is recommended to implement a tight spacing. Therefore, the distance between a producer and an injector is 933 feet, and the distance between two consecutive injectors or producers is 1,320 feet.

II.2.2. The Grid

The grid of the model is oriented parallel to the injector/producer axis in order to avoid diagonal transmissibility issues and have a better visualization of the CO_2 front. The cells' dimensions are 32 ft × 32 ft × 10 ft in x × y × z. There are 31 × 16 × 10 cells in total, i.e. 4,960, but only 2,560 are active to form the triangle illustrated in Figure 8.

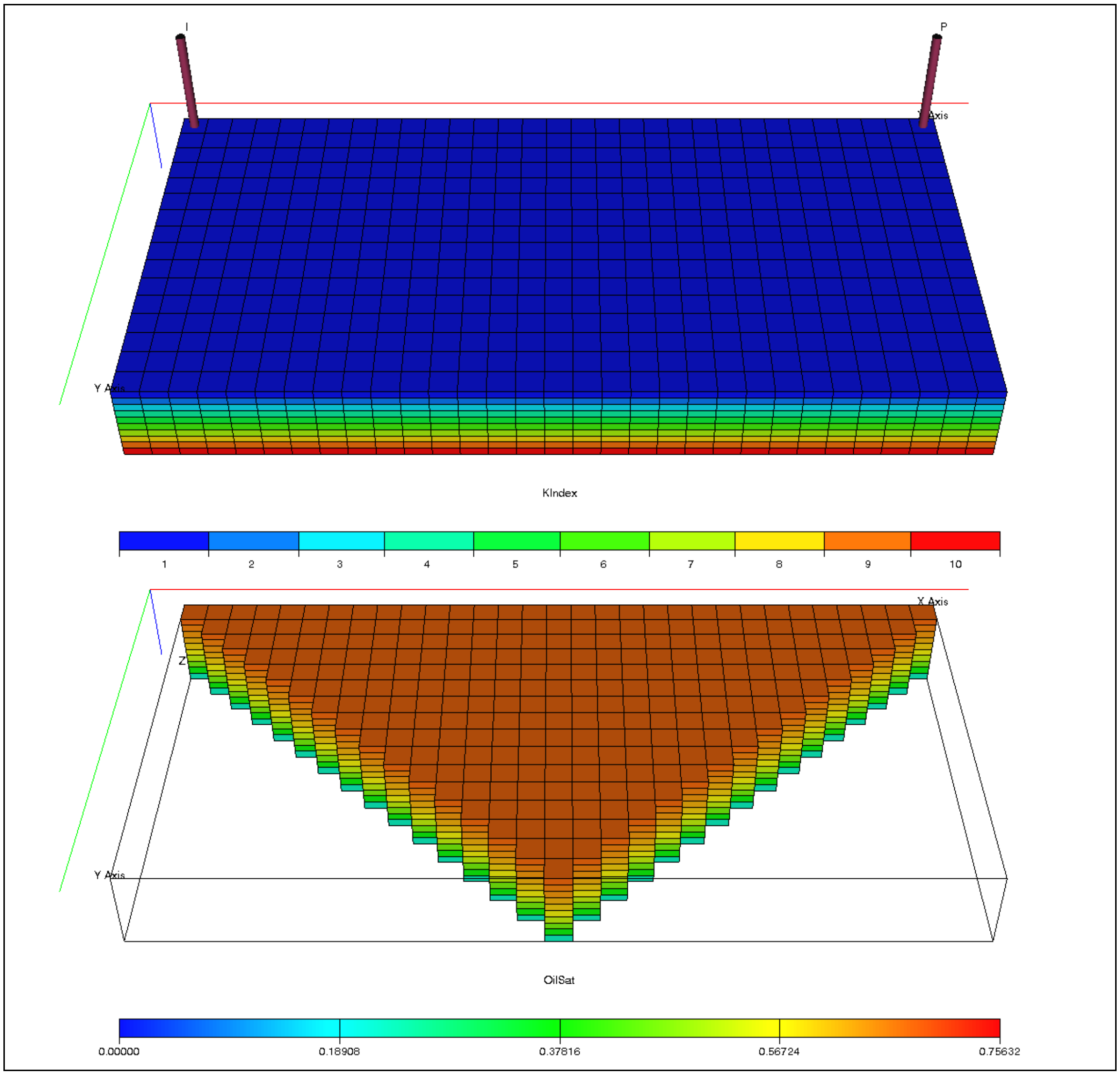

Figure 8: Visualization of the global grid (top, color scale for K index) and the active grid (bottom color scale for initial oil saturation)

This specific way of modeling the 1/8th of a pattern requires correcting the model, since the border cells belong to neighboring triangles as well: the porosity and horizontal permeabilities of the border cells are corrected as shown on Figure 9.

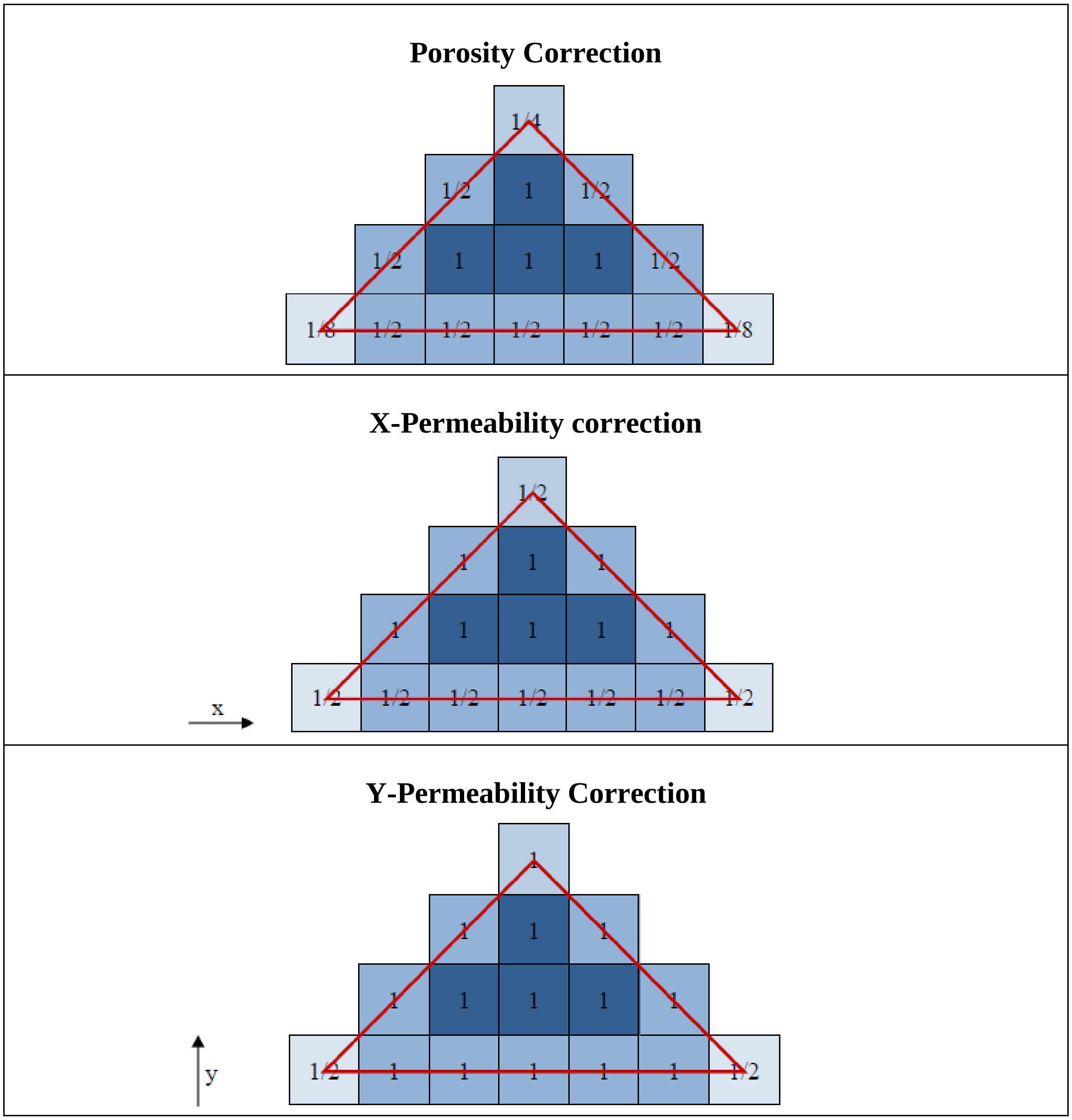

Figure 9: Grid petrophysical modifications to account for the reduced pattern (after Nguyen 2009)

II.2.3. Petrophysics

Following the work of Nguyen (2009), the porosity of the reservoir is considered homogeneous and equal to 20% for every gridblock. The permeability, however, is considered heterogeneous. One way to assess the degree of heterogeneity is from the Dykstra-Parsons coefficient, which is defined as:

$$V_{DP} = 1 - \exp\left(-Var(\ln k_i)\right) \quad \text{.......} (1)$$

Where $Var()$ is the variance of a data set, and k_i is the horizontal permeability of the layer i. V_{DP} varies between 0 and 1. A fully homogeneous reservoir would yield a Dykstra-Parsons coefficient equal to 0, while a very heterogeneous reservoir would yield a V_{DP} that would tend to 1. According to Sahni et al. (2005), most of the fields in the United States have a V_{DP} higher than 0.7.

Following Nguyen (2009), permeabilities are chosen randomly to obtain a V_{DP} of 0.72. The permeabilities retained are given in Table 3. This set of permeabilities yield:

- V_{DP} = 0.7194
- Mean = 180.5 mD
- Standard Deviation = 156.4 mD
- Minimum = 10 mD
- Maximum = 500 mD

Table 3: Horizontal permeabilities of the reservoir layers

Layer	Thickness (ft)	k_h (mD)
1	10	180
2	10	30
3	10	500
4	10	250
5	10	10
6	10	275
7	10	150
8	10	70
9	10	310
10	10	30

The reservoir model was built by alternating high and low permeability layers, as shown on Figure 10. The vertical permeability in each layer is considered to be one tenth of the horizontal permeability.

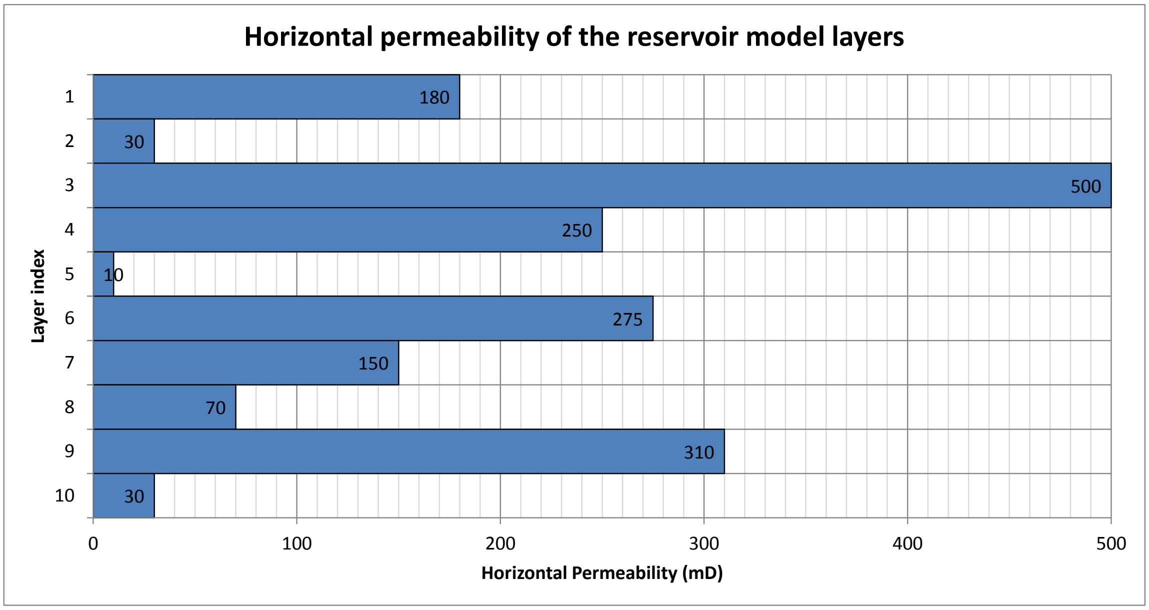

Figure 10: Horizontal permeability of the reservoir layers

II.2.4. Relative Permeabilities

The initial relative permeabilities need to be defined with a three-phase relative permeability model. Using a Corey type model, as described by Ahmadloo et al. (2009), the oil relative permeability is given by:

$$k_{ro} = k_{ro}^{end}\left(\frac{S_o - S_{or}}{1 - S_{or} - S_{wr} - S_{gr}}\right)^{e_o} \qquad \text{.......... (2)}$$

Where k_{or}^{end} is the end-point relative permeability and e_o is the exponent of the relative permeability curve. The equations for the gas phase and the water phase are similar.

Residual saturations and end-point relative permeabilities are chosen from analogs described by Hurter et al. (2007) and Senocak et al. (2008).

Table 4: Parameters for the Corey type relative permeability curves

	Residual saturation (S_r)	End-point relative permeability (k_r^{end})	Relative permeability exponent (e)
Water	0.20	1	1.8
Oil	0.30	0.834	2.0
Gas	0.05	0.834	2.0

Using these parameters, the relative permeability curves are built and shown on Figure 11. The rock modeled is water-wet. Notice the same end points for oil and gas permeability.

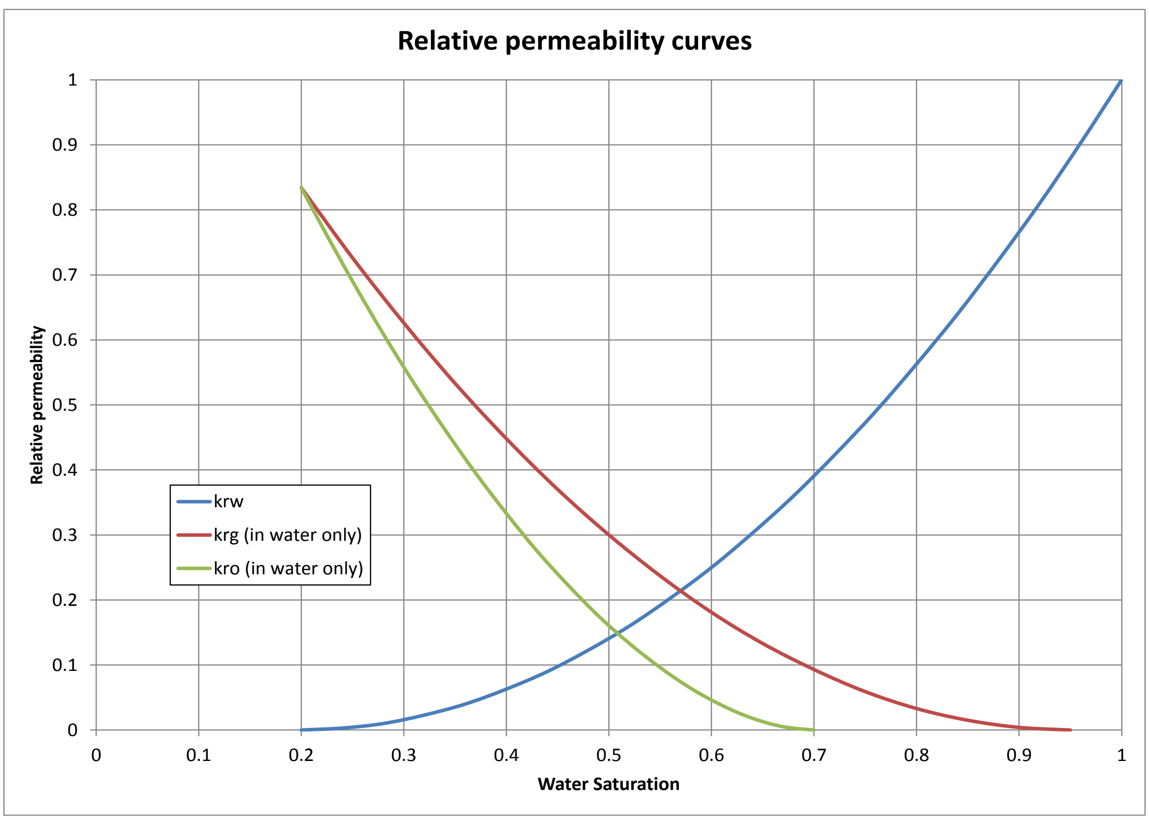

Figure 11: Relative permeability curves generated from the values given in Table 4

II.2.5. Reservoir Initialization

The model is initialized with the parameters corresponding to the fluid sample (see II.1). The initial field pressure is set to 6017 psi at a reference depth of 11,453 feet, which corresponds to the top of the reservoir. The gas-oil contact is set far above the reservoir so that the hydrocarbon content is only oil; contrary to what was analyzed by Nguyen (2009), the water-oil contact here is set at the bottom of the reservoir. This will make the addition of an aquifer at the bottom of the reservoir consistent with the data obtained without an aquifer.

The model has a pore volume of 820,720 resbbl, for an initial hydrocarbon pore volume of 440,622 resbbl. The original oil in place is 308,390 STB, which is equivalent to 61,678 STB/Acre reservoir. Due to the water-oil contact set at the bottom of the reservoir, the average oil saturation in the reservoir is 0.537: the effect of capillary pressure is visible on Figure 12.

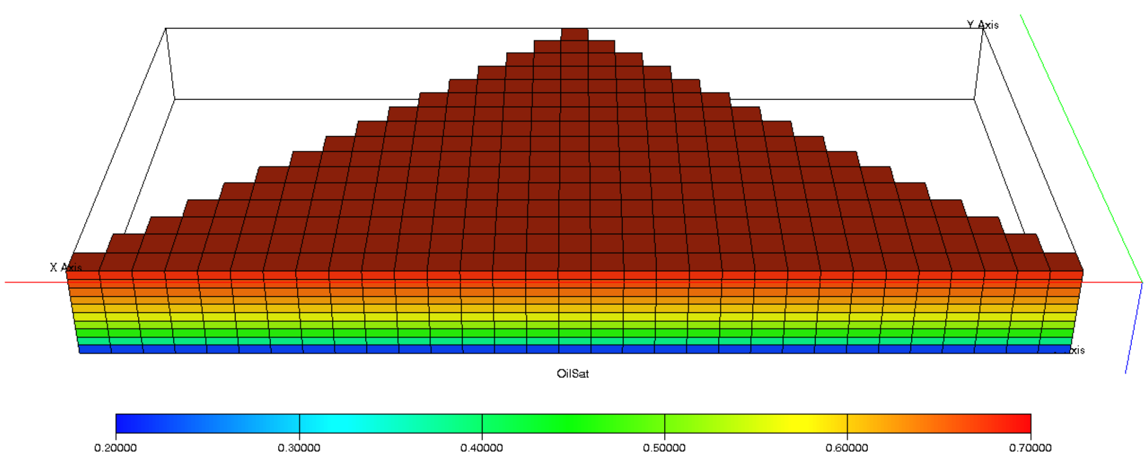

Figure 12: Initial oil saturation in the reservoir

CHAPTER III

ECONOMIC MODEL OF CO_2-EOR PROJECTS

The aim of this thesis is to evaluate and rank different injection and production strategies for miscible CO_2-EOR projects. This leads to changing the injection and production schedules. As a result, one cannot use only the traditional screening criteria of oil production or CO_2 stored: as the oil production is delayed in time, so is the project's revenue stream, and projects with best recovery may not be the best ranked projects on an industrial perspective. This chapter presents the economic model (Figure 13).

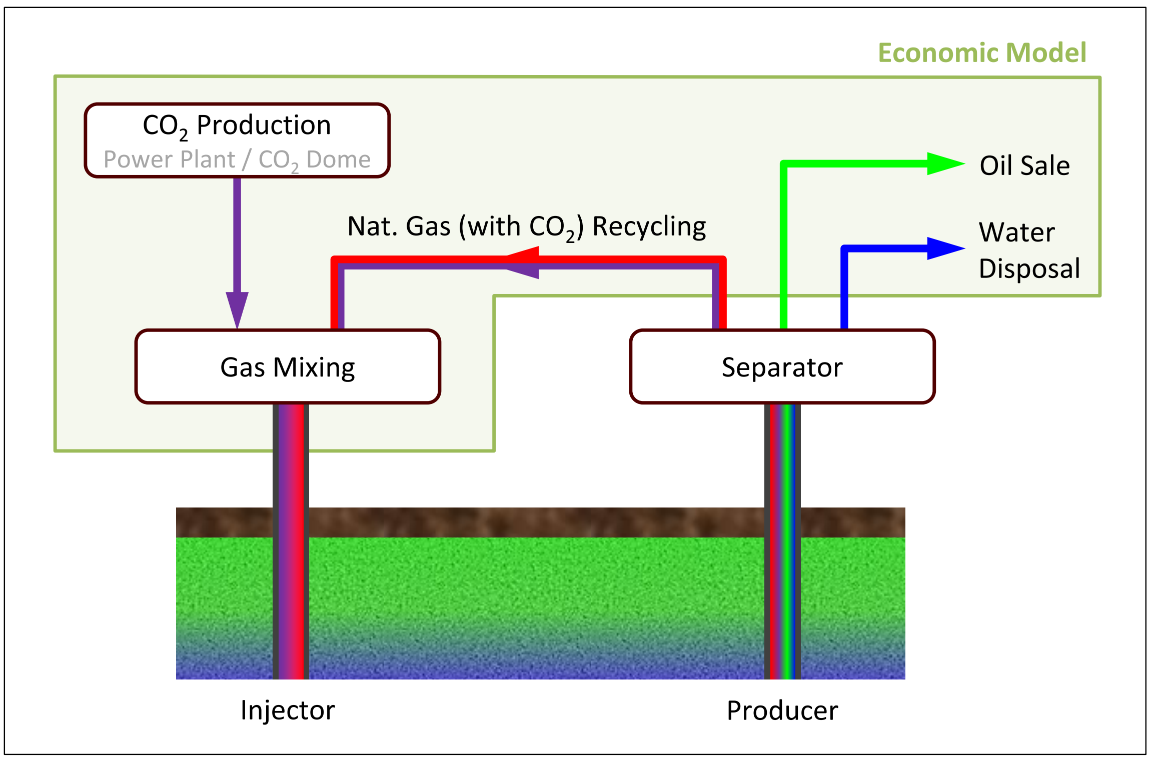

Figure 13: Scope of this chapter: definition of the economic model

III.1. Economic Model Specifications

An economic model will need to handle first the classic functions of economic models of general oil and as projects:

- Products handling: oil sale, gas sale if required, water disposal
- Drilling, completion and abandonment capital expenditures
- Surface facilities capital and operating expenditures
- Operating expenditures: wells, products…

In addition, the model must also handle elements that are specific to CO_2-EOR projects:

- CO_2 generation cost (OpEx)
- CO_2 transport: pumping, pipeline, trucks if necessary (CapEx and OpEx)
- CO_2 market price (OpEx and/or revenue)
- CO_2 recycling (CapEx and OpEx)

The economic model developed in this thesis is a before tax monthly cash flow model, which means that it does not include tax other than production taxes or royalty that are deducted at the source. The reason is that tax regimes are extremely different from one country to another, and even from one US state to the other. Therefore, as a before tax model provides reliable information on the profitability of a project, it is not necessary to build an after tax economic model.

The inputs for the economic model are generated by a reservoir simulation software. The main inputs will be the daily oil production, gas production, water production, and CO_2

imported. Additional inputs may be necessary in order to handle recycling and products prices modeling. For this thesis, the ECLIPSE suite from Schlumberger was used.

III.2. Main Economic Assumptions

The main economic assumptions regard mainly the products' prices and the taxes regime of the project. For this study, the parameters retained are presented in Table 5:

Table 5: Main economic assumptions of the project

Parameter	Value	
Oil Price	$85	/STB
Gas Price	$3.85	/MMBtu
Oil Basis	$0.00	/STB
Gas Basis	$0.00	/MMBtu
Oil Quality Adjustment	$0.00	/STB
Production Taxes	5.0	%
Royalty	25.0	%

The oil price is chosen as the upper limit of the 1st decile of the WTI spot prices in 2011 and 2012 (Figure 14). That is to say, in 2011 and 2012, the oil price has been less than the chosen price for 10% of the time, and more than the chosen price for 90% of the time. $85.00 per STB matches these requirements. If the project is set in another place than the United States, another oil spot price should be used, such as the Brent spot price, for instance.

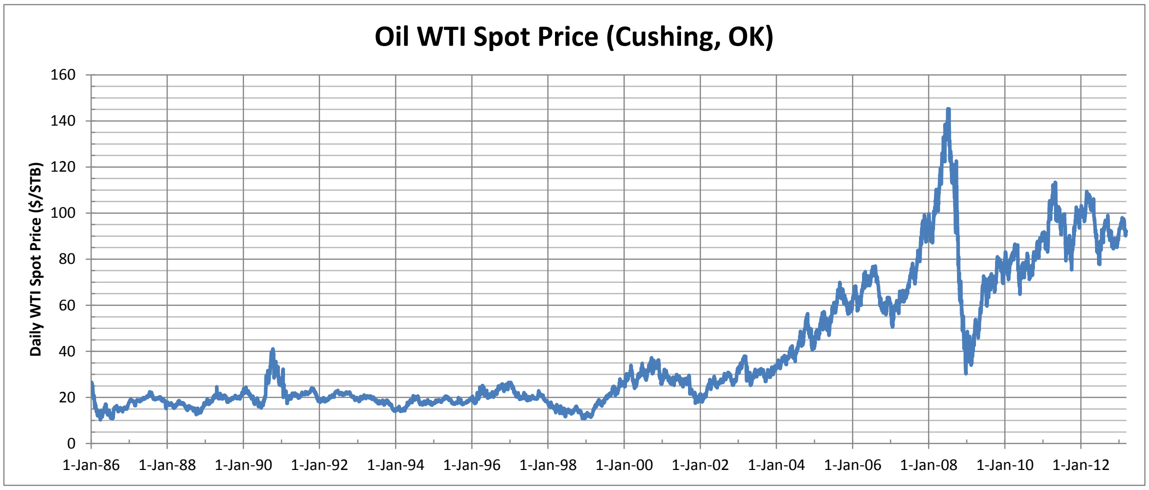

Figure 14: Spot price of the oil on the WTI market from 1986 to 2013 (EIA)

The gas price is set using the same process, as the upper limit of the 1st decile of the gas price in 2011. 2012 is not considered here because of the lower prices of gas that happened that year, but are likely to have a limited time extension (EIA 2011). It should be noted that in most of the projects modeled in this thesis, the gas produced is recycled and therefore not sold.

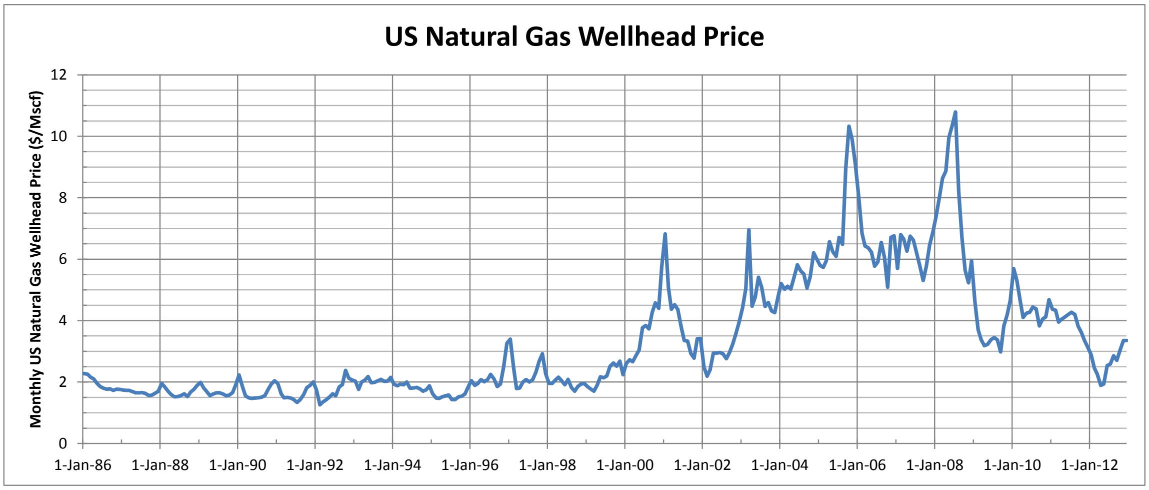

Figure 15: US natural gas wellhead price (EIA)

The oil basis, gas basis and oil quality adjustments are parameters that can be defined by the user. They are set to 0 for the economic modeling of the projects of this thesis.

The royalty and production taxes percentages are typical tax regimes encountered in North America.

III.3. Field Development

For upscaling purposes, it is necessary to choose a number of patterns that will be developed during the project. For this thesis, the development of 40 well patterns is assumed. This is a common order of magnitude for CO_2-EOR projects: for instance, the Weyburn field in Alberta is using 75 patterns (IEA GHG 2009).

III.4. General Cost Functions

This paragraph presents the general cost functions that are not specific to CO_2-EOR projects.

III.4.1. Capital Expenditures

a. Drilling Costs

The drilling cost is derived from Heddle et al. (2003), cited by McCollum and Ogden (2006). The price is scaled up to 2012$. The equation used is:

$$C_{Drill} = 125{,}000 \times \exp(2.44 \cdot 10^{-4} \times DEPTH) \quad \text{(3)}$$

Where C_{Drill} is the drilling cost per well in 2012$, and $DEPTH$ is the drilling depth in feet.

b. Completion Costs

The completion cost mostly consists of the tubing cost C_{Tubing}. It is derived from a study by the EIA (2010) that compiles the lease costs from 1976 to 2009 for oil wells located in the United States, and cost indexes that compare costs to their value in 1976.

The tubing cost is composed of 2 variables: a price index that varies with time only ($Index_t$), and a cost function that varies with depth only ($F(DEPTH)$):

$$C_{Tubing} = Index_t \times F(DEPTH) \quad \text{(4)}$$

To generate a numerical model for $F(DEPTH)$, the data from the EIA study is matched with an exponential function. The tubing costs are downscaled to their 1976 prices to suppress the influence of the price index, and a least squares regression is performed on this dataset. The result of this regression is presented in Figure 16.

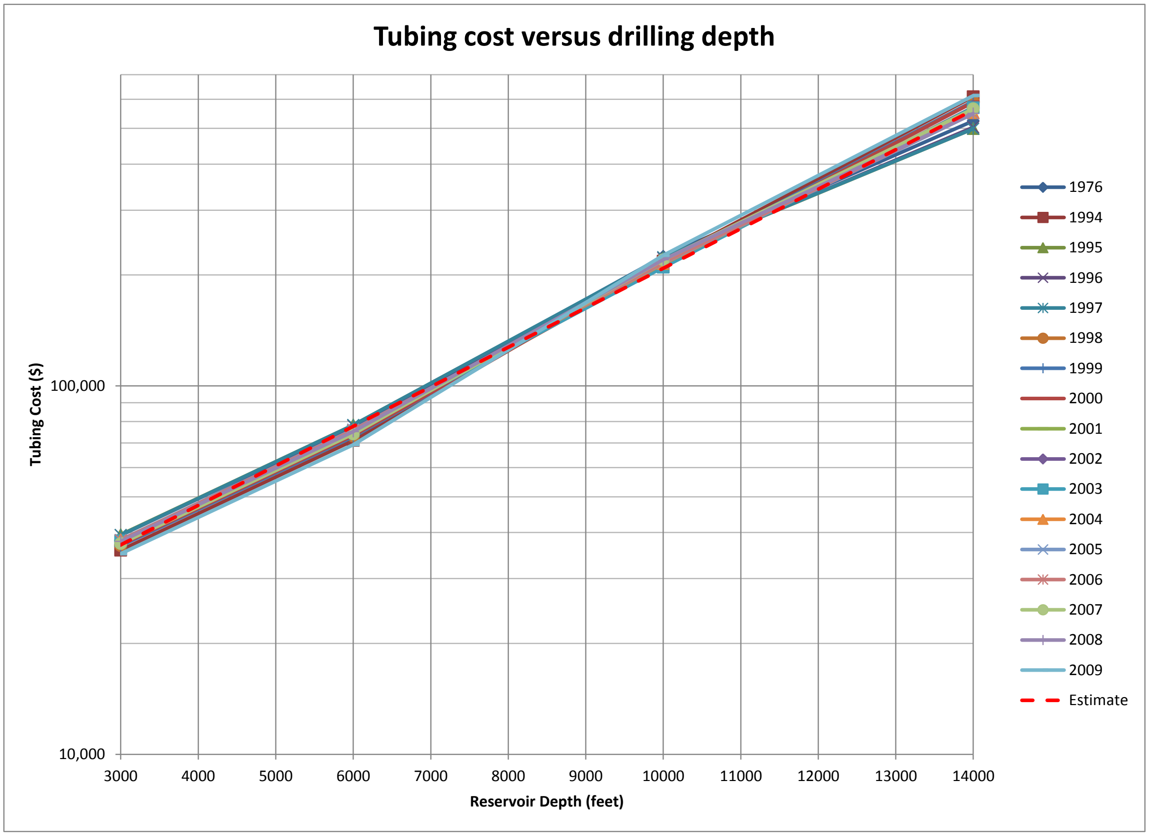

Figure 16: Tubing cost versus drilling depth. All costs are scaled down to 1976 prices using the average price index provided by the IEA

The regression yields the following equation for $F(DEPTH)$:

$$F(DEPTH) = 17{,}646 \times \exp(2.47 \cdot 10^{-4} \times DEPTH) \quad (5)$$

Where $DEPTH$ is the drilling depth in feet. The tubing costs are then obtained by multiplying this cost by the price index that depends on the starting year of the project:

$$C_{Tubing} = Index_t \times 17{,}646 \times \exp(2.47 \cdot 10^{-4} \times DEPTH) \quad \text{.........................} (6)$$

Where C_{tubing} is the tubing cost in 2012 US\$, $Index_t$ is the cost index and $DEPTH$ is the drilling depth in feet.

To evaluate the cost index in 2012, the evolution of the average cost index (Figure 17) is studied. The chosen cost index for 2012 is the average of the cost indexes over the last 6 years of data.

$$Index_{2012} = \frac{1}{6} \times (193 + 307 + 224 + 236 + 232 + 228) = 237 \quad \text{..............} (7)$$

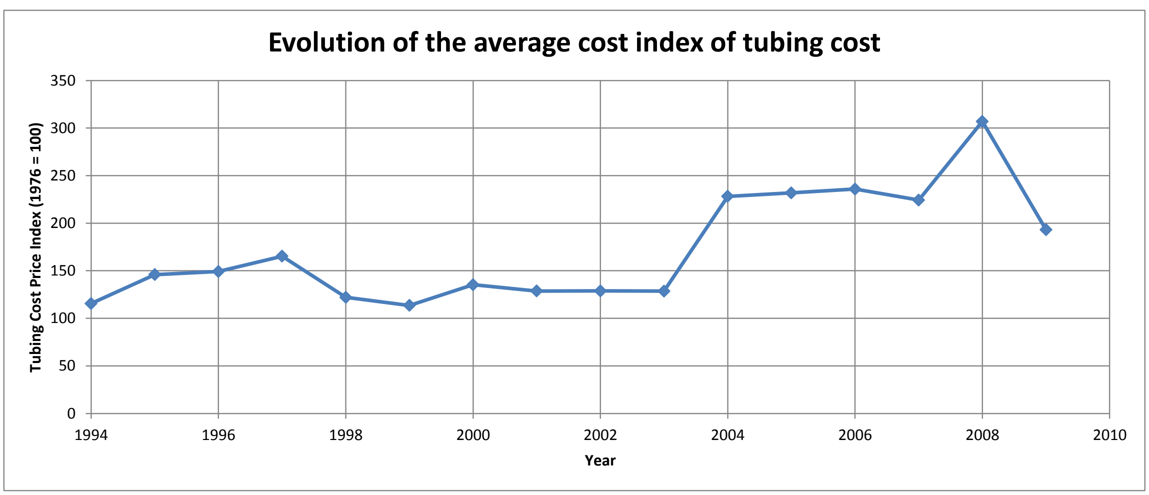

Figure 17: Evolution of the average cost index of tubing cost from 1994 to 2009. Data from EIA (2010)

c. Abandonment Costs

The abandonment cost per well is set to 6.0% of the drilling costs defined in III.4.1.a. This is a typical figure from the IEA study (2010).

$$C_{Abandonment} = 0.06 \times C_{Drill} \quad \text{(8)}$$

Where $C_{Abandonment}$ is the abandonment cost per well in 2012 US$, and C_{Drill} is the drilling cost per well in 2012 US$.

d. Surface Facilities Costs

The surface facilities cost depends on the pattern. Here, for a 5-spot well pattern, following the work of Algharaib and Abu Al-Soof (2008) who used data from the EIA (2010), the capital costs of the surface facilities scaled up to 2012 US$ are:

$$C_{Facilities} = 1{,}333{,}000 + 413.71 \times DEPTH \quad \text{(9)}$$

Where $C_{Facilities}$ is the cost of facilities per pattern in 2012 US$ (for a 5 spot pattern, one pattern corresponds to 2 wells belonging only to each pattern), and $DEPTH$ is the reservoir depth in feet.

III.4.2. Operating Costs

a. Fixed Operating Costs

From the EIA study (2010), the fixed operating costs correspond on average to 0.50% of the drilling costs defined in III.4.1.a.

$$OpEx_{Fixed} = 0.005 \times C_{Drill} \quad (10)$$

Where $OpEx_{Fixed}$ are the fixed operating expenditures per well per month in 2012 US$, and C_{Drill} is the drilling cost in 2012 US$. This is valid for both production and injection wells.

b. Variable Costs – Production

The variable costs for oil and gas production, and water disposal can be set by the user. In this thesis, the values chosen are typical values for oil fields in the United States, calculated from a study by the EIA (2010). They are presented in Table 6:

Table 6: Production variable costs per well

Parameter	Value	
Oil Variable Costs	$0.50	/STB
Gas Variable Costs	$0.05	/Mscf
Water Disposal Costs	$1.00	/STB

c. Variable Costs – Gas Recycling and Injection

Gas injection and recycling costs account for gas compression and recycling. For the range of pressures used in this project, they are defined in Table 7:

Table 7: Injection variable costs per well

Parameter	Value
Gas Variable Costs	\$0.80 /Mscf

III.5. Cost Functions Specific to CO_2-EOR

III.5.1. CO_2 Generation

As these projects have a goal of CO_2 storage, the injected CO_2 is assumed to come from a power plant that is fitted with a CO_2 capture facility. The cost of generating CO_2 is taken from a study by the IEA (2011), which uses the Levelized Cost Of Electricity (LCOE) approach derived in a previous study by the IEA and the OECD (2010).

The Levelized Cost Of Electricity is defined as the electricity price that would cancel the net present value of a project, at a given discount rate.

$$Discounted\ Revenues - Discounted\ Costs = 0 \quad \text{(11)}$$

$$\sum_t \left(\frac{Electricity_t \times P_{Electricity}}{(1+r)^t} \right) - \sum_t \left(\frac{CapEx_t + OpEx_t + Fuel_t + Carbon_t + Decom_t}{(1+r)^t} \right) = 0 \quad \text{.... (12)}$$

Considering a fixed price of electricity equal to the LCOE, we have $LCOE = P_{Electricity}$ and therefore:

$$LCOE = \frac{\sum_t \left(\left(CapEx_t + OpEx_t + Fuel_t + Carbon_t + Decom_t \right) \times \frac{1}{(1+r)^t} \right)}{\sum_t \left(Electricity_t \times \frac{1}{(1+r)^t} \right)} \quad \text{......... (13)}$$

The levelized cost of electricity can be computed on power plants with and without CO_2 capture. Using these 2 values, the cost of CO_2 avoided is calculated as follows (in US$ per metric ton of CO_2):

$$Cost\ of\ CO_2\ avoided = \frac{LCOE_{\text{w/ capture}} - LCOE_{\text{w/o capture}}}{Emissions_{\text{w/ capture}} - Emissions_{\text{w/o capture}}} \quad \text{......... (14)}$$

For the existing technologies the IEA (2011) calculated the values shown in Table 8:

Table 8: CO_2 generation costs for existing technologies

Power Plant Type	**CO_2 Generation Cost**	
Coal Plants		
Post-combustion	$58	/mton of CO_2
Pre-combustion – IGCC	$43	/mton of CO_2
Pre-combustion – PC	$55	/mton of CO_2
Oxy-combustion	$52	/mton of CO_2
Natural Gas Plants		
Post-Combustion	$80	/mton of CO_2

In this study, the value retained is the median, i.e. $55/mton of CO_2, which corresponds to a pulverized coal plant retrofitted with a pre-combustion capture facility.

III.5.2. CO_2 Compression

CO_2 is typically captured in gaseous phase and transported in dense phase. As a consequence, the pressurization of CO_2 at the entrance of the pipeline is first carried out using compressor trains, until the pressure is high enough for the CO_2 to be in dense phase. From that point, the CO_2 is compressed using pumps. The cut-off pressure in standard conditions is 1070 psi.

a. Compressors Capital Costs

It is assumed that 5 compressors are used in series. After Mohitpour et al. (2007), the compression ratio of each compressor should be the same, equal to:

$$CR = \left(\frac{P_{cut-off}}{P_{initial}}\right)^{\frac{1}{N_{stage}}} \quad (15)$$

Considering 5 stages here, the compression ratio is set to 2.36. The compressor power requirement for each stage is then given by:

$$W_{s,i} = \left(\frac{1000}{24 \times 3600}\right)\left(\frac{mZ_sRT_{in}}{M\eta_{is}}\right)\left(\frac{k_s}{k_s - 1}\right)\left(CR^{\frac{k_s-1}{k_s}} - 1\right) \quad (16)$$

The compressor power requirements parameters are shown in Table 9.

Table 9: Compressor power requirements parameters

Acronym	Parameter	Value	Unit
$W_{s,i}$	Compressor power requirement for each stage		kW
m	CO_2 mass flow rate		mton/day
R	Ideal gas constant	8.314	J/mol-K
T_{in}	Inlet CO_2 temperature	313.15	K
M	CO_2 molar mass	44.01	g/mol
η_{is}	Compressor efficiency	0.75	-
Z_s	Average CO_2 compressibility factor in each stage		-
k_s	Dimensionless gas exponent		-

For this study, following McCollum and Ogden (2006), we consider a compressor train of 5 compressors. Each compressor operates at an internal temperature of 356 K (104 °F). The properties of CO2 for the pressure and temperature in each stage is provided by Jarrell et al. (2002). The parameters for each compressor stage are shown in Table 10.

Table 10: Compressor stages parameters

Parameter	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Unit
P_{in}	14.6	35	81	191	452	psi
P_{out}	35	81	191	452	1070	psi
Z_s	0.995	0.985	0.970	0.935	0.845	-
k_s	1.277	1.286	1.309	1.379	1.704	-

The power requirement of the computer train is computed with:

$$W_{Comp} = \sum_{i=1}^{5} W_{s,i} \qquad (17)$$

However, according to the IEA GHG (2002), the maximum size of a compressor train based on current technology is 40,000 kW. If the required compression power is larger than this limit, the CO_2 flow must be split into several trains that will operate at a lower power. Therefore, the number of compressor trains is computed by:

$$N_{trains} = \text{ROUNDUP}\left(\frac{W_{Comp}}{40{,}000}\right) \qquad (18)$$

The capital costs are expressed using the CO_2 flow rate in each compressor train:

$$m_{train} = \frac{m}{N_{train}} \quad \text{......} (19)$$

$$C_{Comp} = m_{train}N_{train}\left(32.3 \times (m_{train})^{-0.71} + 1{,}291 \times (m_{train})^{-0.60} \ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right) \quad \text{.......} (20)$$

Where C_{Comp} is the capital cost of the compressors in 2012 US\$, m_{train} is the CO_2 flow rate in each compressor train in mton/day.

b. Pumps Capital Costs

To raise the CO_2 pressure to the desired pipeline inlet pressure of 2200 psi, pumps are used. The pumping power required, from the IEA GHG (2002), is:

$$W_{Pump} = \frac{1000 \times 10}{24 \times 36 \times 145.03795} \times \frac{m(P_{final} - P_{cut-off})}{\rho_{CO_2}\eta_P} \quad \text{......} (21)$$

Where W_P is the pump pressure (kW), m is the CO_2 mass flow rate (mtons/day), P_{final} is the pump outlet pressure (2200 psi), $P_{cut-off}$ is the cut-off pressure (1070 psi), ρ_{CO_2} is the average CO_2 density in the pump (630 kg/m^3) and η_P is the pump efficiency (0.75).

The capital costs of the pumps are derived from the required pump power:

$$C_{Pump} = 1{,}305{,}000 \times \frac{W_P}{1000} + 82{,}300 \quad \text{......} (22)$$

Where C_{Pump} is the pumps capital cost in 2012 US$, and W_P is the pumps power, in kW. These costs have been compared against the costs for the existing projects of Sleipner and Weyburn (Torp and Brown 2004) and they are consistent with them.

c. Compression Unit Operating Costs

The operating costs of the compression unit (compressor trains and pumps) are split in fixed operation and maintenance (O&M) costs that are a fraction of the capital costs each year, and the cost of the electric power needed to operate them.

$$\begin{aligned} OpEx_{Compression} &= O\&M + Electricity \\ &= 0.04 \times (C_{Comp} + C_{Pump}) + P_{Electricity} \times (W_{Comp} + W_{Pump}) \times 24 \times 365 \end{aligned} \quad \text{.... (23)}$$

Where $OpEx_{Compression}$ are the operational expenditures due to CO_2 compression in 2012 US$ and $P_{Electricity}$ is the price of electricity in $/kWh. Following McCollum and Ogden (2006), a price of 0.070$/kWh is assumed. One can check on Figure 18 that this is a fairly safe assumption, regarding the retail prices of electricity over the past decade.

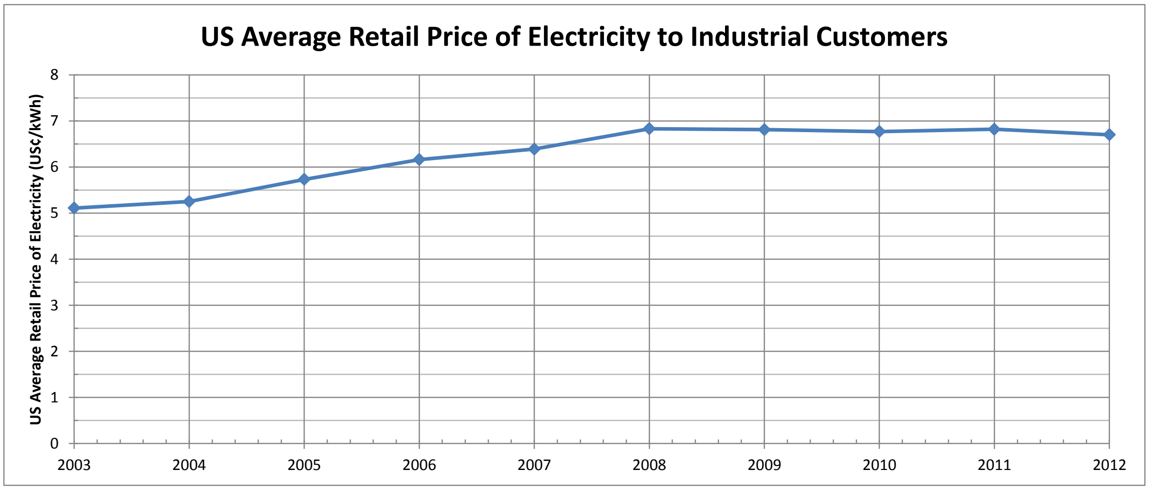

Figure 18: Average retail price of electricity to industrial customers in the United States (EIA 2013)

III.5.3. CO_2 Transport

The CO_2 transport from the source to the field is handled by a pipeline that is designed to transport a chosen percentage of the peak needs of CO_2. For this study, the percentage of peak capacity chosen is 80%, unless specified otherwise. When the pipeline capacity is exceeded, the remaining of the CO_2 is transported with trucks, which are more expensive than pipeline.

a. Pipeline Transport

The building costs of the pipeline are compiled from several models (Heddle et al. 2003; Hendriks et al. 2003; IEA GHG 2002; McCollum and Ogden 2006; Parker 2004). The aim of this part is to derive a model where the pipeline cost depends only on the mass flow rate m and the pipeline length L. Following the work of McCollum and Ogden, all models have been scaled to the same basis to be compared (Table 11 and Table 12).

Table 11: Common design bases for the comparison of existing pipeline cost models

Common Design Bases		
Plant Capacity Factor	80	%
Pipeline Inlet Pressure	2200	psi
Pipeline Outlet Pressure	1500	psi
CO_2 Temperature	77	°F
CO_2 density	55.2	lb/ft^3
CO_2 Density @ STP	1.965	kg/Nm^3
CO_2 Viscosity	0.0606	cP

Table 12: Common economic bases for the comparison of existing pipeline cost models

Common Economic Bases		
Reference Cost Year	2005	
Conversion Euro-Dollar	1.20	
Operational Lifetime	20	years
Discount Rate	10	%
Location Factor	1.00	
Terrain Factor	1.20	
Electricity Cost	0.04	$/kWh

Using these common economic bases, the pipeline capital cost (in \$/km) can be plotted versus the CO_2 mass flow rate. From this plot, 3 estimates can be made: mean, low and high (Figure 19). Low and high estimates correspond to the models that yield the lowest and highest pipeline costs. The estimates obtained, scaled up to 2012\$, are the following:

- Low estimate: $C_{P,low} = 9{,}803 \times m^{0.40} \times L^{0.06}$ .... (24)
- Mean estimate: $C_{P,mean} = 10{,}405 \times m^{0.42} \times L^{0.13}$ .... (25)
- High estimate: $C_{P,high} = 8{,}255 \times m^{0.50} \times L^{0.13}$ .... (26)

Where C_P is the non-scaled pipeline capital cost in US\$/mi, m is the mass flow rate in mtons/day and L is the pipeline length. The exponent for the mass flow rate is derived from the match shown on Figure 19. The exponent for the pipeline length is derived by McCollum and Ogden (2006).

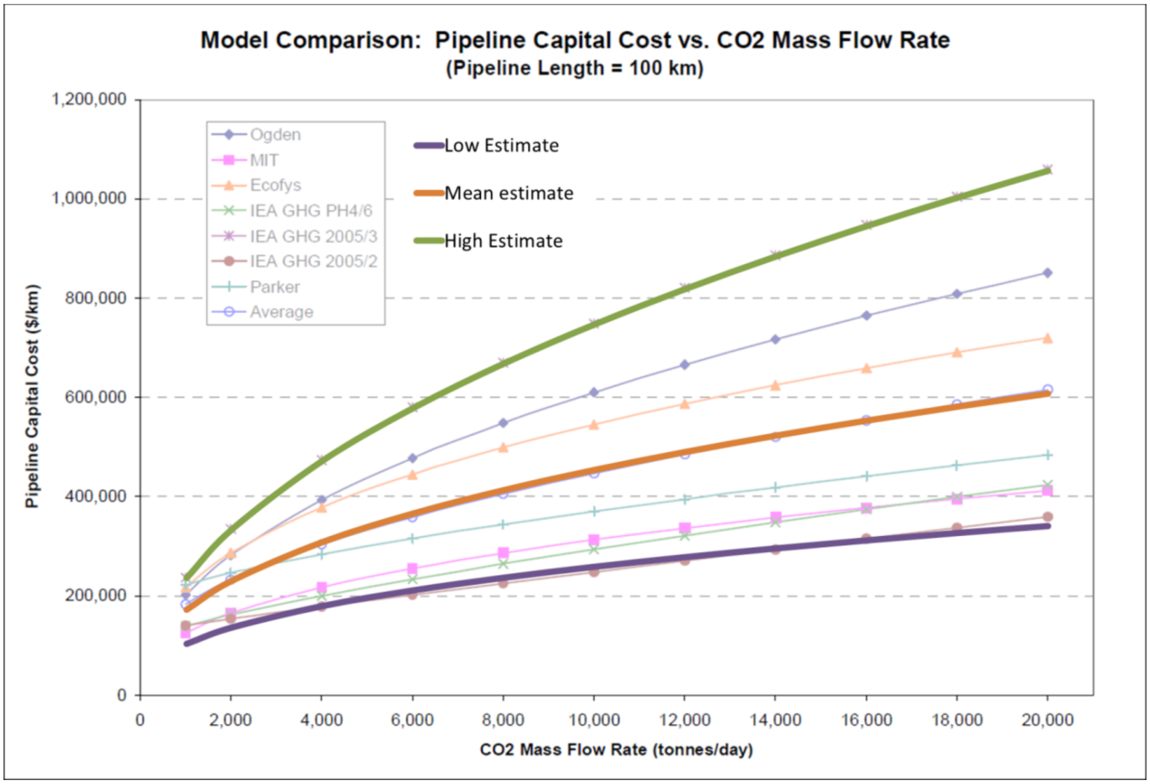

Figure 19: Comparison of pipeline capital cost models and estimates (modified from McCollum and Ogden, 2006)

To account for the location of the project and the possible terrain settings that can impact the cost of the pipeline, the cost is scaled up with a dimensionless location factor (F_L) and a dimensionless terrain factor (F_T). A list of location and terrain factors is provided by the IEA GHG (2002) and reproduced in Table 13 and

Table 14.

$$C_{Pipeline} = F_L \times F_T \times C_P \quad \text{.......} \quad (27)$$

Where $C_{Pipeline}$ is the upscaled pipeline capital cost in 2012 US$, F_L is the dimensionless location factor, F_T is the dimensionless terrain factor and C_P is the non-scaled pipeline capital cost defined above. For this study, a location factor corresponding to the United States ($F_L = 1.00$) and a terrain factor corresponding to cultivated land ($F_T = 1.10$) are assumed.

Table 13: List of location factors

Location	F_L
USA / Canada	1.0
South America	0.8
Europe	1.0
UK	1.2
North africa	0.8
Equatorial Africa	0.9
South Africa	0.7
Russia	0.7
Middle East	0.9
Indian sub-continent	0.7
SE Asia (exc. Japan)	0.8
Japan	1.0
China / Central Asia	0.7
Australia / NZ	1.0

Table 14: List of terrain factors

Building terrain setting	F_T
Grassland	1.00
Offshore	2.00
Cultivated land	1.10
Wooded	1.05
Jungle	1.10
Stony desert	1.10
> 20% mountainous	1.30
> 50% mountainous	1.50

The pipeline operating expenditures are taken as 2.5% of the capital expenditures each year. This value is approximately the average of a handful of studies made on CO_2 transport (Heddle et al. 2003; Hendriks et al. 2003; IEA GHG 2002, 2005b).

$$OpEx_{Pipeline} = 0.025 \times C_{Pipeline} \quad (28)$$

The pipeline diameter can be derived from the following formula (IEA GHG 2005a):

$$D_{Pipe} = \frac{1}{0.0254} \times \sqrt{\frac{4 \times m}{\pi \times \rho_{CO_2} \times v_{CO_2}}} \quad (29)$$

Where D_{Pipe} is the pipeline diameter in inches, m is the CO_2 mass flow rate in kg/s, ρ_{CO_2} is the CO_2 density in kg/m^3 (in this study, we consider a CO_2 density of 0.884 kg/m^3 in the pipeline, based on the conditions defined in Table 11) and v_{CO_2} is the CO_2

velocity in the pipeline (2.0 m/s in this study). The pipe diameter is not used further in the economic model, but it is given as useful information.

b. Truck Transport

When the CO_2 needs exceed the pipeline capacity, the remainder is transported by trucks. The cost of CO_2 transport in trucks was calculated by Odenberger and Svensson (2003). The operational expenditures linked to truck transport are $28.2 per metric ton of CO_2 in excess per 100 miles.

III.5.4. CO_2 Market Price

In the model, the user is able to set a market price for CO_2. That is to say, the operator of the project will get additional revenues for the CO_2 stored, and additional expenses for the CO_2 emitted. Unless specified otherwise, the assumption in this thesis is that there is no CO_2 market price or tax.

III.6. Inputs from the Reservoir Simulation Software

The daily inputs required from the reservoir simulation software (ECLIPSE for this thesis) are the given in Table 15:

Table 15: Required outputs from the reservoir simulator

Output from the reservoir simulator	Unit	ECLIPSE keyword
Oil Production Total	STB	FOPT
Gas Production Total	Mscf	FGPT
Water Production Total	bbl	FWPT
Gas Injection Total	Mscf	FGIT
Oil Density	lb/ft^3	FODN
Injector Bottom Hole Pressure	psi	WBHP:I
Components Injection Total	lb-mole	FCMIT_i
Components Production Total in Liquid phase	lb-mole	FCOMT_i
Components Production Total in Gas phase	lb-mole	FCGMT_i

These outputs are analyzed to yield the monthly values of the following monthly functions:

- Wellhead Oil Production
- Wellhead Gas Production
- Wellhead Water Production
- Wellhead Gas Injection (Imported CO_2 + Recycled gas)
- CO_2 Imported from the CO_2 source (a power plant in this study)
- CO_2 Recycled
- Oil Density
- Produced Gas Heating Value

The monthly oil density is computed from the daily oil densities as:

$$\rho_{oil,m} = \frac{1}{FOPT_m - FOPT_{m-1}} \sum_{days} \rho_{oil,d} \times (FOPT_d - FOPT_{d-1}) \quad \text{.................. (30)}$$

The monthly gas heating value is computed from the daily components production in the gas phase:

$$HV_m = \sum_{days} \left(\sum_{i=1}^{N_{comp}} HV_i \times y_{i,d} \right) \quad \text{.. (31)}$$

Where $y_{i,d}$ is the molar fraction of component i at day d, computed by:

$$y_{i,d} = \frac{FCGMT\_i_d - FCGMT\_i_{d-1}}{\sum_{i=1}^{N_{comp}} FCGMT\_i_d - \sum_{i=1}^{N_{comp}} FCGMT\_i_{d-1}} \quad \text{....................................... (32)}$$

III.7. Outputs of the Economic Model

The economic model computes a monthly cash flow from the inputs given by ECLIPSE. From this monthly cash flow, investment yardsticks are computed. These yardsticks are used as screening criteria to rank the strategies tested based on economics. The yardsticks calculated are:

- Net Present Value at 10% discount rate (PV10, in $)
- Internal Rate of Return (IRR, in %)
- Profitability Index at 10% discount rate (PI)
- Payout period (undiscounted and at 10% discount rate, in months)

- Technical cost for oil production (undiscounted and at 10% discount rate, in $/stb)
- Technical cost for total production (undiscounted and at 10% discount rate, in $/boe)

NB: If the produced gas is recycled, both technical costs are equal since the gas production is not sold. If not, the equivalency is made using 6 Mscf = 1 boe, as an energy equivalency (Lohrenz 1999).

III.8. Summary of the Economic Model

A summary of the equations used in the economic model is presented hereafter:

Table 16: Summary of the Economic Model

Model element	**CapEx**	**OpEx**
Production wells	$C_{Drill} = 125{,}000 \times \exp(2.44 \cdot 10^{-4} \times DEPTH)$ $C_{Tubing} = Index_t \times 17{,}646 \times \exp(2.47 \cdot 10^{-4} \times DEPTH)$ $C_{Abandonment} = 0.06 \times C_{Drill}$	$OpEx_{Fixed} = 0.005 \times C_{Drill}$ $OpEx_{oil} = 0.50$ \$/stb $OpEx_{gas} = 0.05$ \$/Mscf $OpEx_{water} = 1.00$ \$/bbl
Injection Wells	$C_{Drill} = 125{,}000 \times \exp(2.44 \cdot 10^{-4} \times DEPTH)$ $C_{Tubing} = Index_t \times 17{,}646 \times \exp(2.47 \cdot 10^{-4} \times DEPTH)$ $C_{Abandonment} = 0.06 \times C_{Drill}$	$OpEx_{Fixed} = 0.005 \times C_{Drill}$ $OpEx_{gas} = 0.80$ \$/Mscf
Surface Facilities	$C_{Facilities} = 1{,}333{,}000 + 413.71 \times DEPTH$	
CO_2 Generation		$OpEx_{CO_2} = 43 - 80$ \$/mton
CO_2 Compression	$C_{Comp} = m_{train} N_{train} \left(32.3 \times (m_{train})^{-0.71} + 1{,}291 \times (m_{train})^{-0.60} \ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right)$ $C_{Pump} = 1{,}305{,}000 \times \frac{W_P}{1000} + 82{,}300$	$OpEx_{Compression} = 0.04 \times (C_{Comp} + C_{Pump}) + P_{Electricity} \times (W_{Comp} + W_{Pump}) \times 24 \times 365$
CO_2 Transport	$C_{Pipeline,low} = 9{,}803 \times m^{0.40} \times L^{0.06}$ $C_{Pipeline,mean} = 10{,}405 \times m^{0.42} \times L^{0.13}$ $C_{Pipeline,high} = 8{,}255 \times m^{0.50} \times L^{0.13}$	$OpEx_{Pipeline} = 0.025 \times C_{Pipeline}$ $OpEx_{Truck} = 28.2$ \$/mton in excess
CO_2 Market Price		$OpEx_{CO_2} = -$ \$/mton

CHAPTER IV

REFERENCE CASE MODEL SELECTION AND OPTIMIZATION

Most existing models use simple assumptions for the injection and production schedule. Using the hybrid reservoir simulator economic model, it is possible to evaluate more sophisticated schedules. The aim of this chapter is to define a solid simple injection and production schedule that is optimized enough to make a good reference model.

IV.1. Reference Case Model Overview

IV.1.1. Main Principle

The schedule is based on the conclusions of Nguyen (2009). The main constraint is to keep the bottomhole pressure of the injector above the minimum miscibility pressure (MMP), to ensure CO_2 miscibility in the oil. Therefore, the reservoir is produced by natural depletion until the bottomhole pressure of the injector falls to 5200 psi. At this point, injection is triggered, and the injector injects all the produced gas (of which CO_2 content will increase over time) plus as much imported CO_2 as necessary to maintain the pressure.

IV.1.2. Model Constraints

In addition to the injector's bottomhole pressure target, the producer is controlled by its maximum oil rate and maximum gas rate. The aim of this chapter is to determine optimal constraints for these maximum rates. An additional constraint is that a plateau of at least 3 years is required for the oil production, as it would be the case in an industrial project. All the constraints of the model are presented in Table 17.

Table 17: Reference Case model constraints

Model Constraint	Value	Unit
Producer		
Oil Production Plateau	≥ 3	years
Maximum Oil Rate	To Be Determined	stb/d
Maximum Gas Rate	To Be Determined	Mscf/d
Injector		
Bottom Hole Pressure	≥ 5200	psi
Injection Trigger	BHP ≤ 5200	psi
Produced gas re-injected as is		

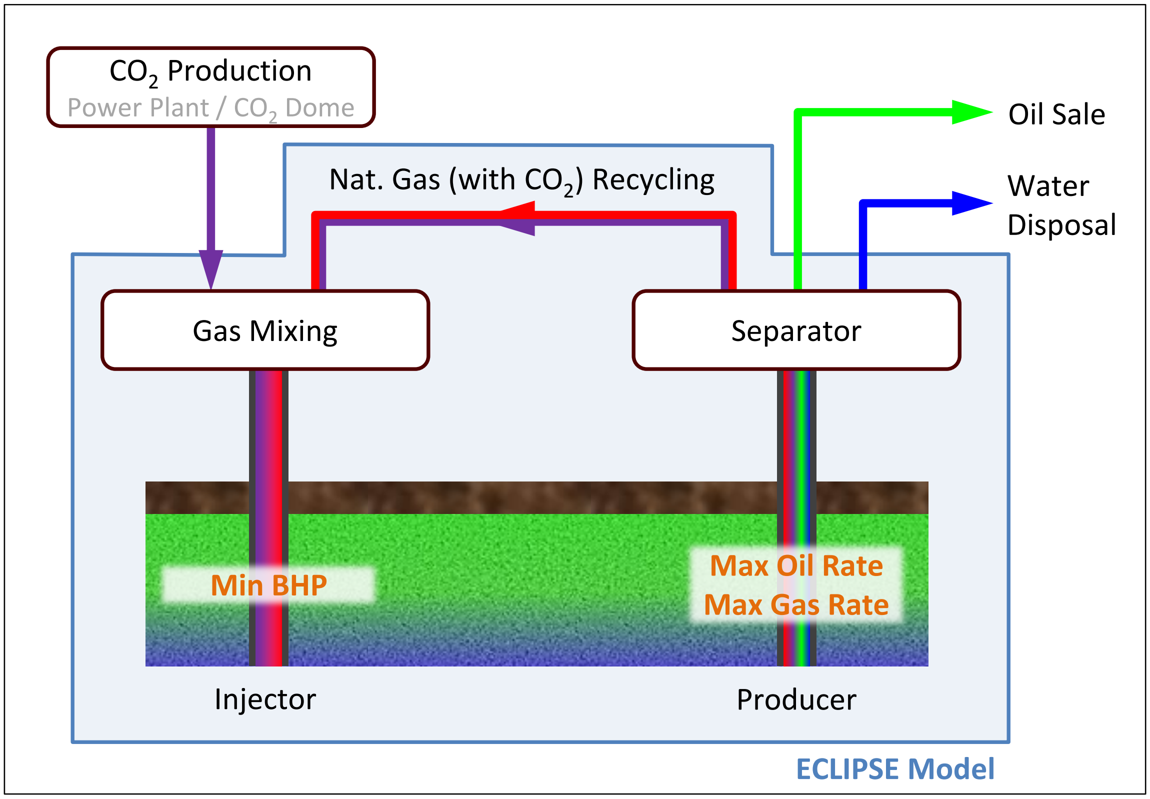

Figure 20: Overview of the main controls of the Reference Case (in orange)

IV.1.3. Typical Behavior

For this model, the global behavior of the field is the following. After a brief phase of natural depletion, CO_2 injection starts, maintaining the bottomhole pressure of the injector at 5200 psi and the field pressure at a value close to that. For a while, the field produces at a steady rate and gas-oil ratio, since the CO_2 injection maintains the reservoir pressure.

When CO_2 breaks through, the gas rate starts increasing, while the oil rate remains constant at its limit rate. The gas rate keeps increasing until the maximum gas rate limit of the producer is reached. At this moment, the producer switches from oil rate control to gas rate control, and the oil rate is not sustainable any more: this corresponds to the end of the oil production plateau. The oil rate then keeps decreasing steadily until the end of the project. This behavior is well shown on Figure 21.

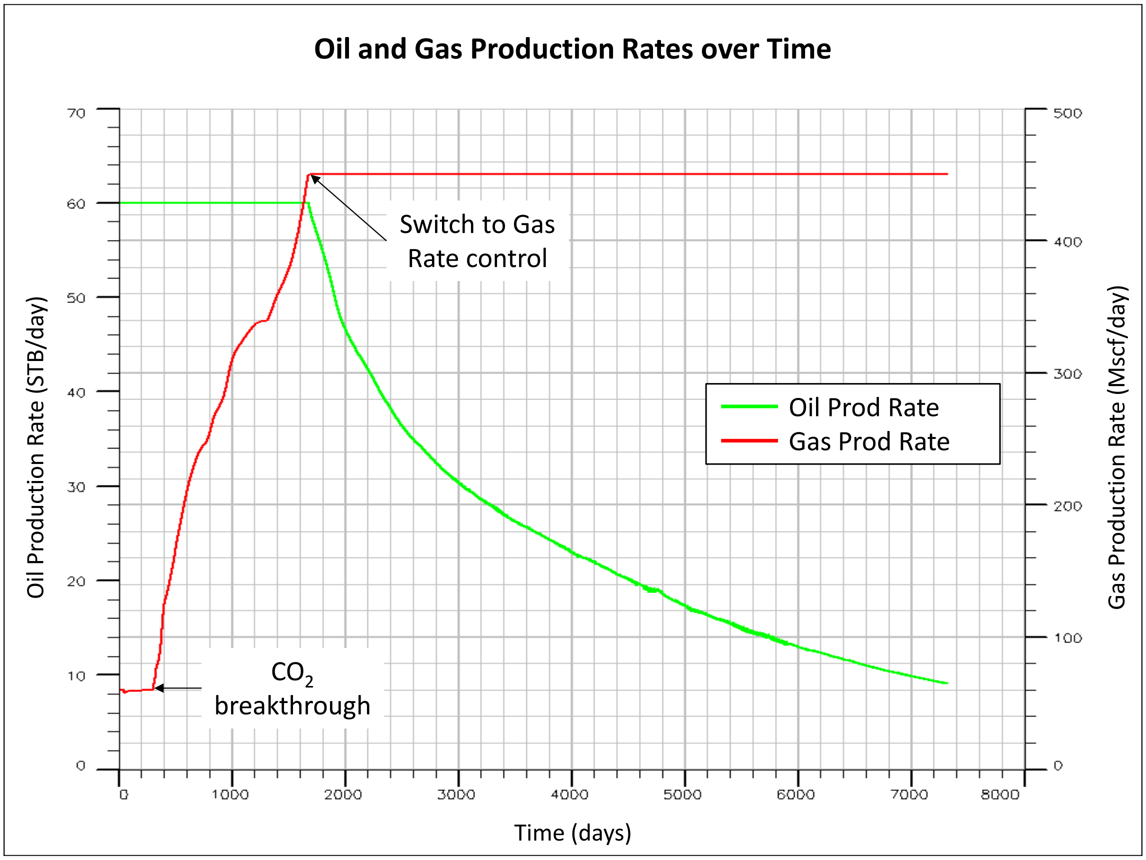

Figure 21: Typical behavior of the oil and gas production rates for the Reference Case. On this example, the constraints are set to 60 STB/day for the oil rate, and 450 Mscf/day for the gas rate.

The problem solved in this chapter is the following: how should the maximum oil and gas production rates be set to optimize the model, and how can we assess the relative performance of different projects?

IV.2. Sensitivity Analysis to the Production Constraints

IV.2.1. Proposed Runs and Screening Criteria

182 runs have been made, with the following maximum rates:

- Maximum Oil Rate: 25 to 85 STB/day, every 5 STB/day
- Maximum Gas Rate: 150 to 800 Mscf/day, every 50 Mscf/day

To evaluate the different sets of constraints, 4 screening criteria are used. They are presented in Table 18.

Table 18: Screening criteria for the Reference Case

	Screening criteria	**Unit**	**Target**
1	Oil Production Plateau Duration	years	Must be ≥ 3 years
2	Total Oil Production	STB	Maximum
3	Total CO_2 Imported	Mscf	Maximum
4	Max Gas-Oil Ratio during Plateau	Mscf/STB	Minimum

For the Reference Case, it is not necessary to use economic measures as screening criteria. Since the schedule is not sophisticated, and the injection and production curves have the same global behavior, oil recovery and CO_2 imported are enough to judge of the quality of a schedule.

The values for these screening criteria can be found in APPENDIX 6.

IV.2.2. Results of the Screening Criteria

a. Oil Production Plateau Duration

The plateau duration is the first screening criterion in importance. A project cannot be selected if the oil production plateau lasts less than 3 years, for economic reasons: the production and export facilities are designed to handle a certain amount of production, which corresponds to the maximum oil production. If the plateau is too short, facilities will be built to handle oil rates that will occur during a limited time, and will therefore be oversized and thus cot more than they should. A 3-year plateau is a value commonly used in the industry for 20-year long projects. The plateau duration for all the runs is shown on Figure 22.

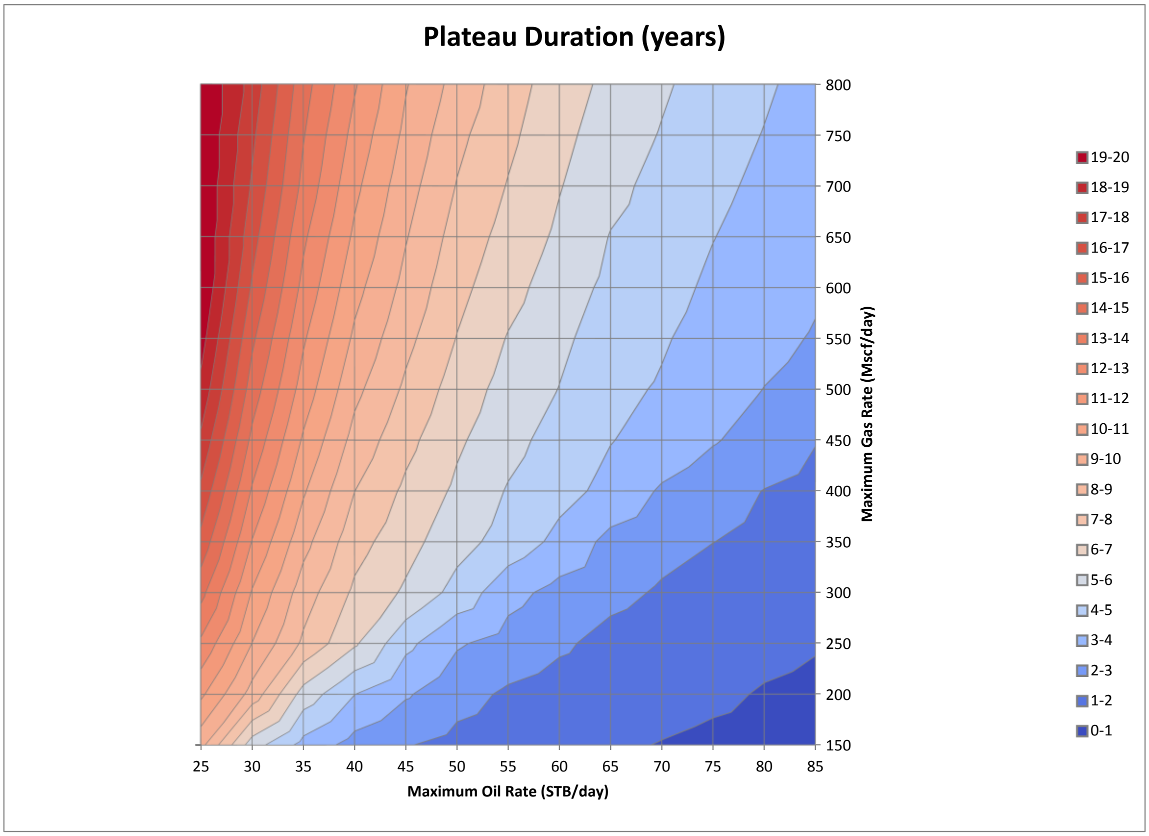

Figure 22: Plateau duration for all the runs of the Reference Case[1]

This figure shows well the behavior of the plateau duration with the 2 constraints that we are trying to optimize: it increases if the maximum oil rate decreases, or if the maximum gas rate increases. However, it does not show properly the way the criterion (Plateau ≥ 3 years) is fulfilled or not.In addition, it is interesting to add a constraint on the upper limit of the plateau duration: on an economic point of view, having a very long plateau is not optimal, because it means that there is probably a way to recover the oil faster.

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[1] The color scale used here is a 2-hue diverging color scale, as recommended by Moreland (2008) for accurate visualization of scientific data.

Therefore, it was decided to scale this criterion from 0 to 1, 0 being not desirable, 1 being wanted. The attribution of 0 to 1 is made as follows:

- Plateau duration < 3 years: 0
- Plateau duration from 3 to 7 years: 1
- Plateau duration from 7 to 20 years: Linear decrease from 1 at 7 years to 0 at 20

This scaling is illustrated on Figure 23:

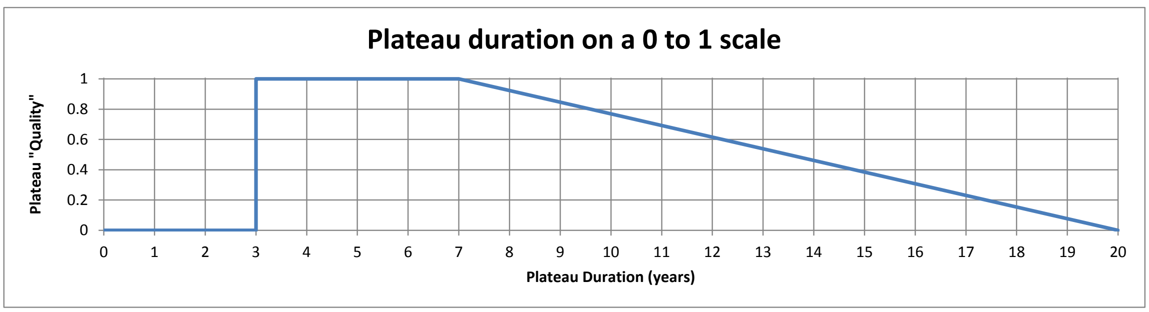

Figure 23: Scaling of the "plateau duration" criterion from 0 to 1

The result of this scaling is shown on Figure 24. It clearly shows that there is a range of couples of high maximum oil rates coupled with low maximum gas rates that cannot be considered, based on this criterion.

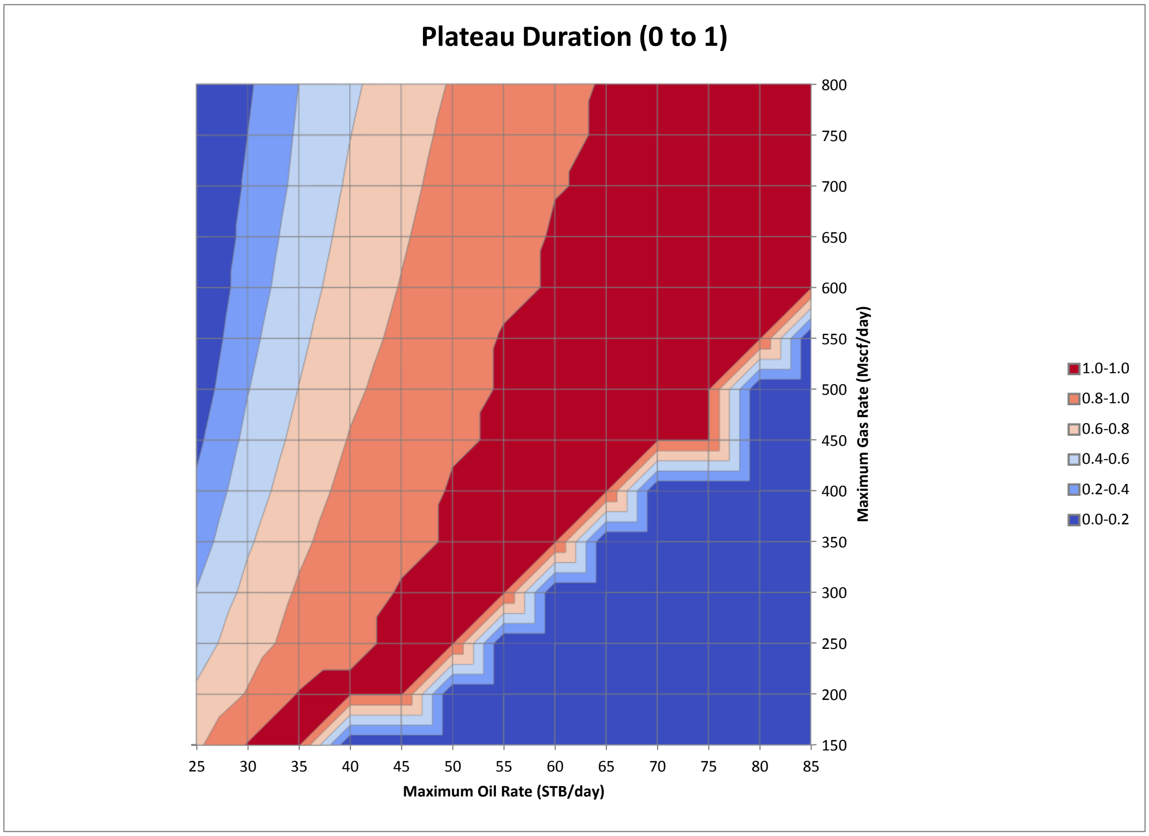

Figure 24: Visualization of the "plateau duration" criterion, scaled from 0 to 1 (0, blue, is not wanted; 1, red, is wanted)

b. Total Oil Production

The total oil production for all the runs is plotted on Figure 25. It is then scaled from 0 to 1 by linearly interpolating and associating 0 to a 0 STB total oil production, and 1 to the maximum oil production encountered.

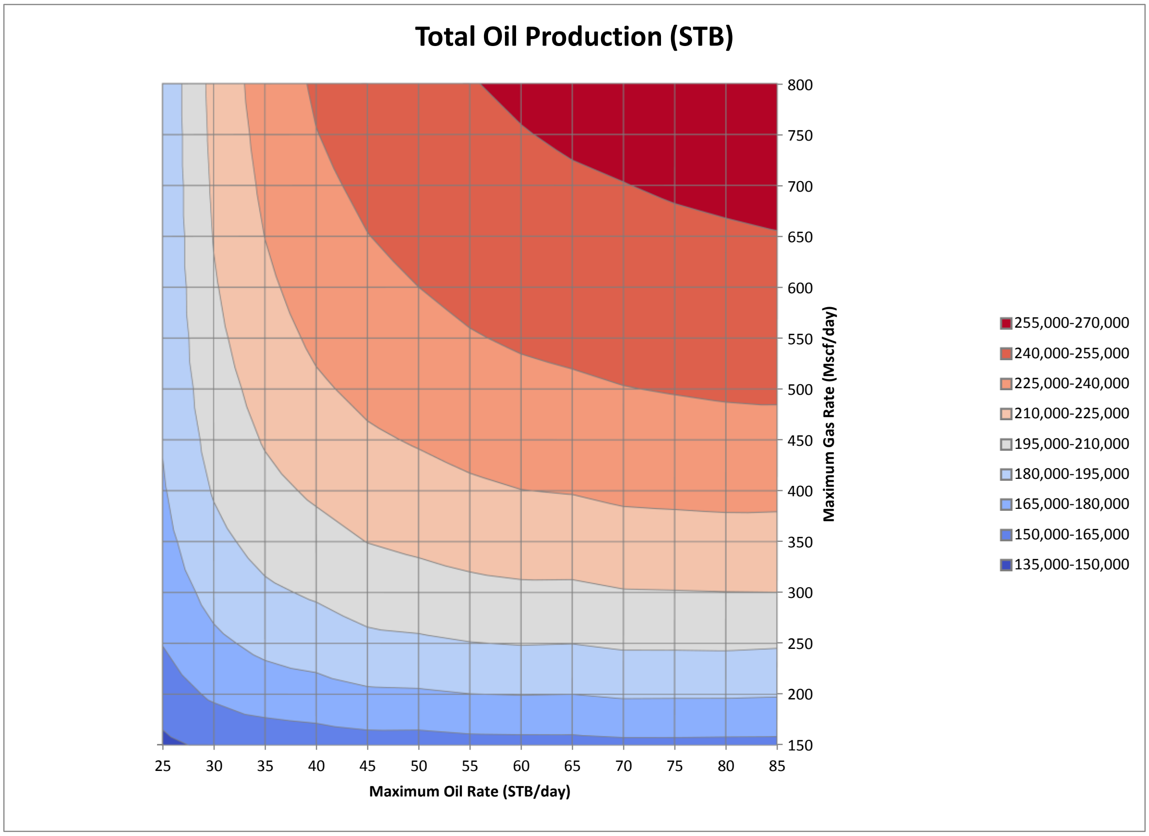

Figure 25: Total oil production for all the runs of the Reference Case

c. Total CO_2 Imported

As we are considering CO_2-EOR projects as potential ways to store CO_2, the total CO_2 imported is a key criterion. The target is to make it as high as possible. For all the runs, the results are given on Figure 26. It is then scaled from 0 to 1 by linearly interpolating and associating 0 to a 0 Mscf total CO_2 imported, and 1 to the maximum CO_2 imported encountered.

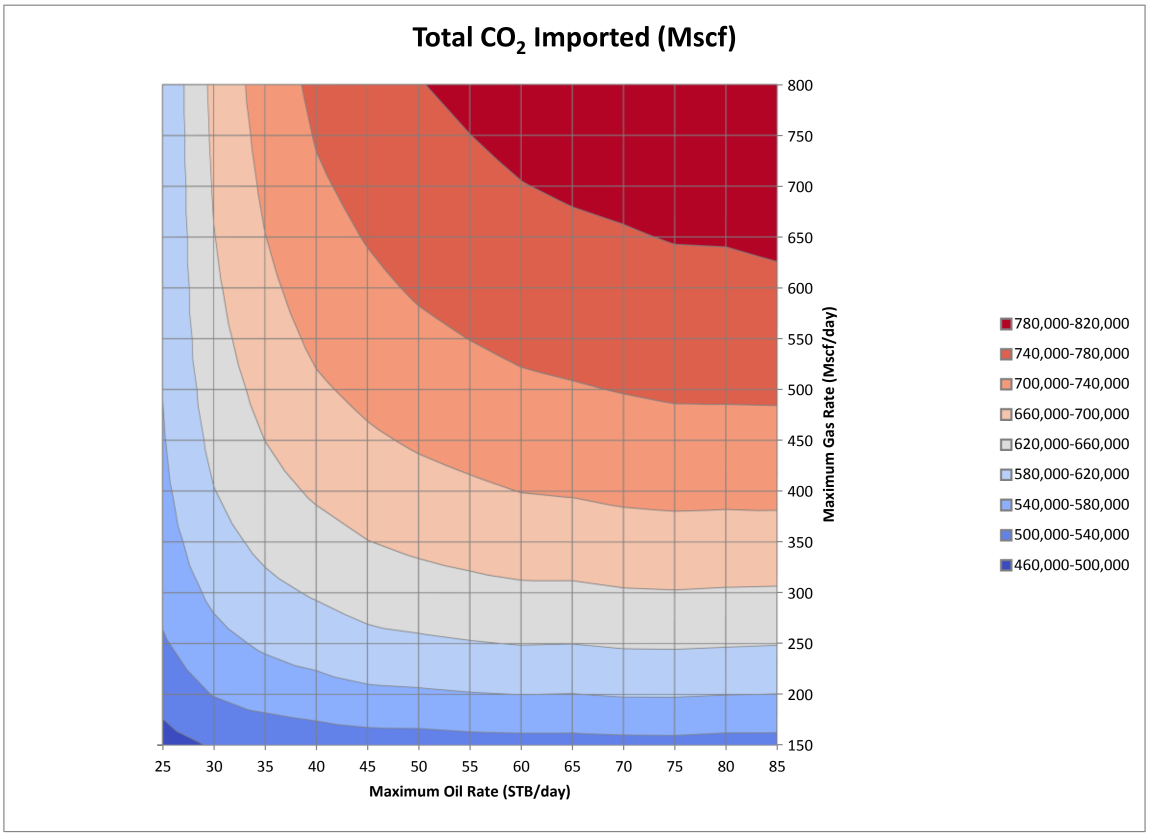

Figure 26: Total CO_2 imported for all the runs of the Reference Case

d. Maximum Gas-Oil Ratio during Plateau

The Maximum Gas-Oil Ratio should be as low as possible. All the results are shown synthetically on Figure 27. It is then scaled from 0 to 1 by linearly interpolating and associating 0 to the maximum gas-oil ratio encountered, and 1 to the minimum gas-oil ratio encountered.

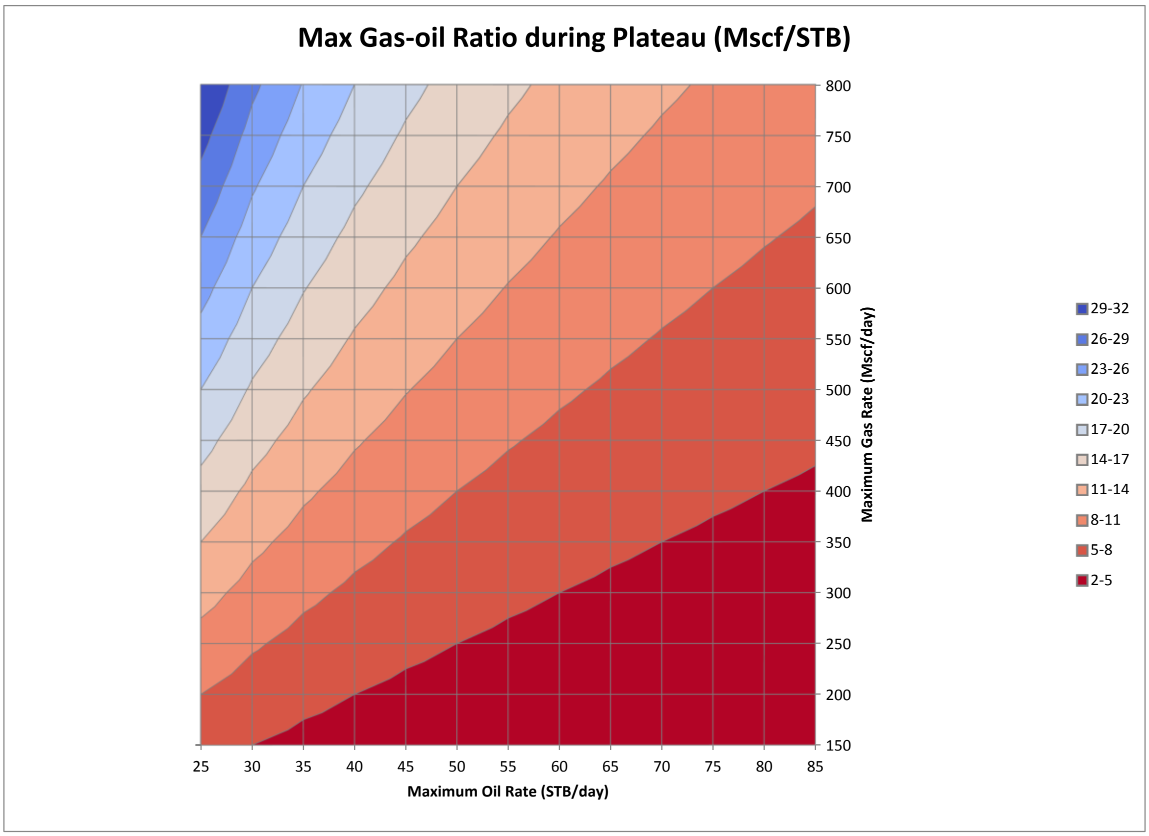

Figure 27: Maximum gas-oil ratio during plateau for the runs of the Reference Case

IV.3. Optimal Constraints Combination

All the screening criteria scaled from 0 (bad) to 1 (good) are shown on Figure 28.

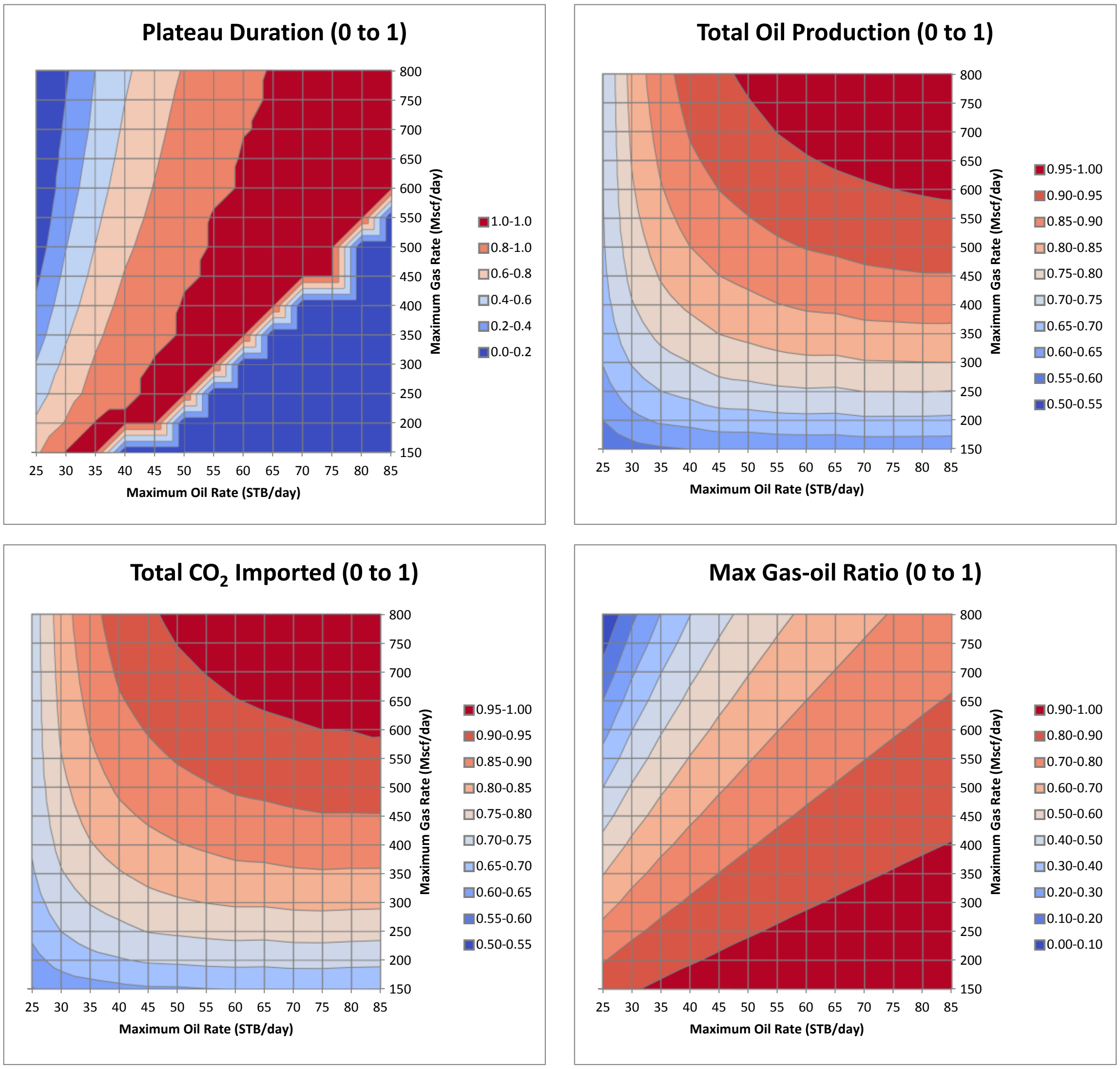

Figure 28: All screening criteria for the Reference Case scaled from 0 to 1

All these screening criteria are combined into one synthetic chart, shown on Figure 29. From this figure, it is possible to pick the Reference Case model constraints that will be the most effective regarding this set of criteria.

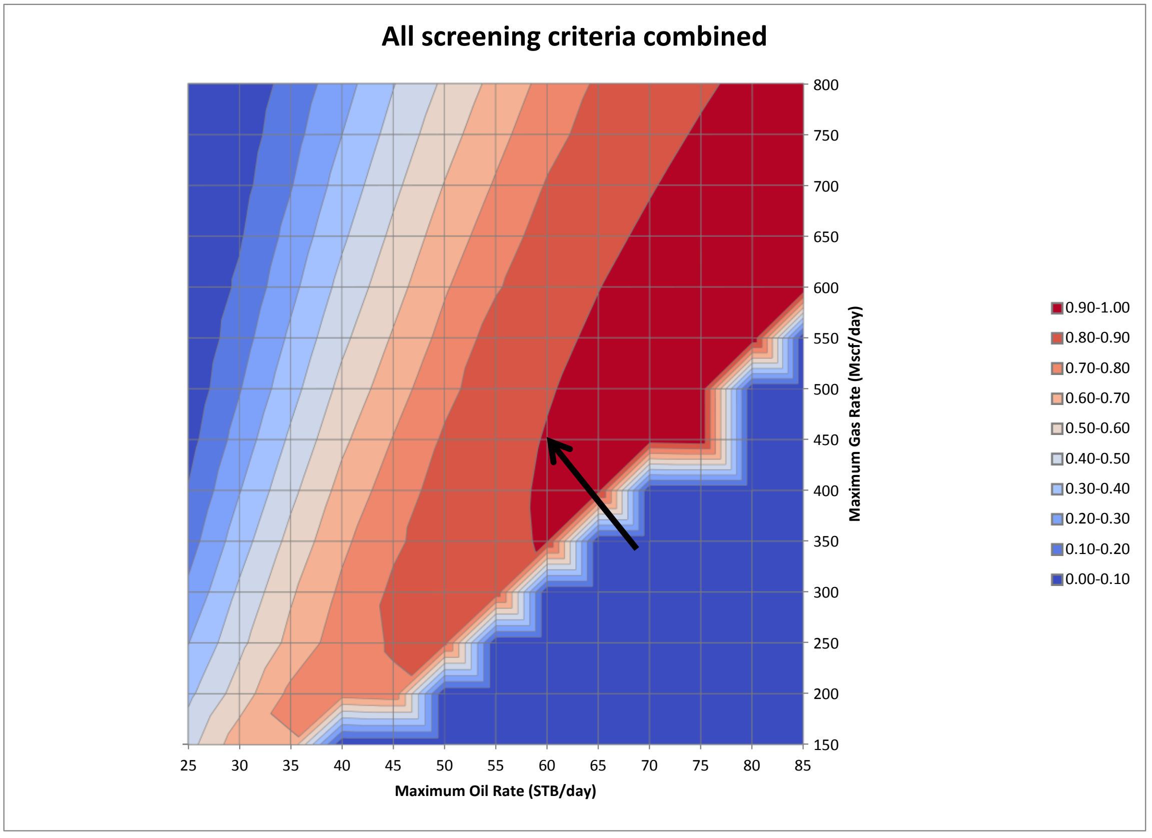

Figure 29: All screening criteria of the reference case combined

The red area represents the "hot" zone, i.e. the area where the model constraints should be picked to optimize the chosen criteria. The chosen maximum rates are indicated by the arrow. They correspond to the lowest maximum oil rate in the red area (the lower the maximum oil rate, the longer the plateau and the more flexibility to improve the schedule), combined with the highest maximum corresponding gas rate (the higher the maximum gas rate, the longer the plateau and the better the oil recovery and the CO_2 storage).

The updated set of constraints for the reference case is therefore given in Table 19.

Table 19: Chosen constraints for the Reference Case

Model Constraint	Value	Unit
Producer		
Oil Production Plateau	≥ 3	years
Maximum Oil Rate	60	stb/d
Maximum Gas Rate	450	Mscf/d
Injector		
Bottom Hole Pressure	≥ 5200	psi
Injection Trigger	BHP ≤ 5200	psi
Produced gas re-injected as is		

IV.4. Overview of the Reference Case

Some metrics for the Reference Case are presented hereafter:

Table 20: Value of the screening criteria for the Reference Case

Parameter	Value	Unit
Plateau duration	4.6	years
Oil recovered	231,236	STB
Recovery factor	74.9	%
CO_2 imported	718,430	Mscf
	37,800	mtons
Storage density	18.1	lb/ft^3

Table 21: Some economic metrics for the Reference Case

Parameter	Value	Unit
Present Value @ 10%	$858,087,598	
Internal Rate of Return	44.1	%
Profitability Index @ 10%	2.55	
Payout (undiscounted)	27	months
Technical cost (undiscounted)	$41.16	/STB

IV.5. Limitations of the Reference Case

This Reference Case passes all the tests on the economics and the recovery. However, it has a limited industrial potential because of the decreasing needs of imported CO_2. This is a consequence of the fact that as CO_2 breaks through and is produced from the reservoir, the CO_2 content of the recycled gas gradually increases. Therefore, the proportion of imported CO_2 versus recycled CO_2 in the injection stream decreases over time (Figure 30).

As the proportion of recycled gas in the injection stream increases, the import CO_2 rate decreases (Figure 31). On an industrial project, this would not be sustainable because in order to implement CO_2 capture, the CO_2 provider needs to ensure that there is a viable market. Therefore, the Reference Case defined in this chapter will be used as a base point to implement alternative strategies that include a more constant CO_2 supply.

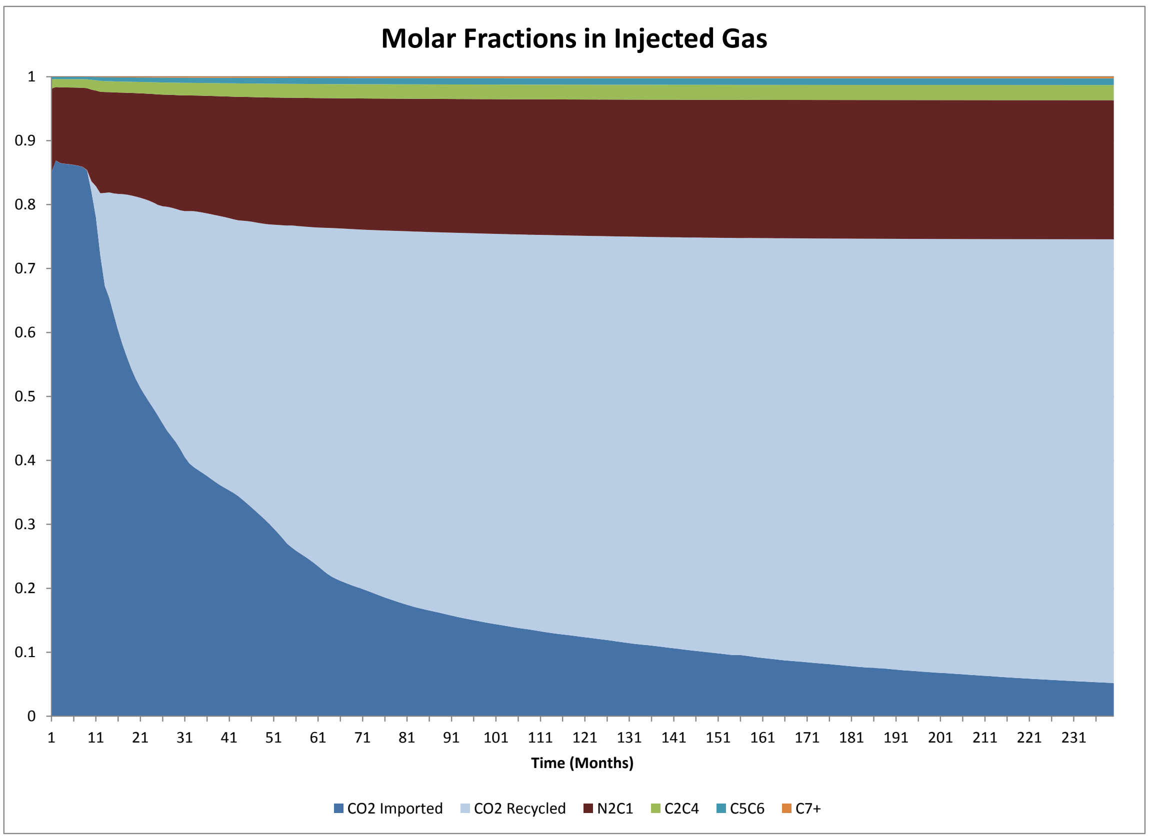

Figure 30: Evolution of the molar fractions in the injected gas

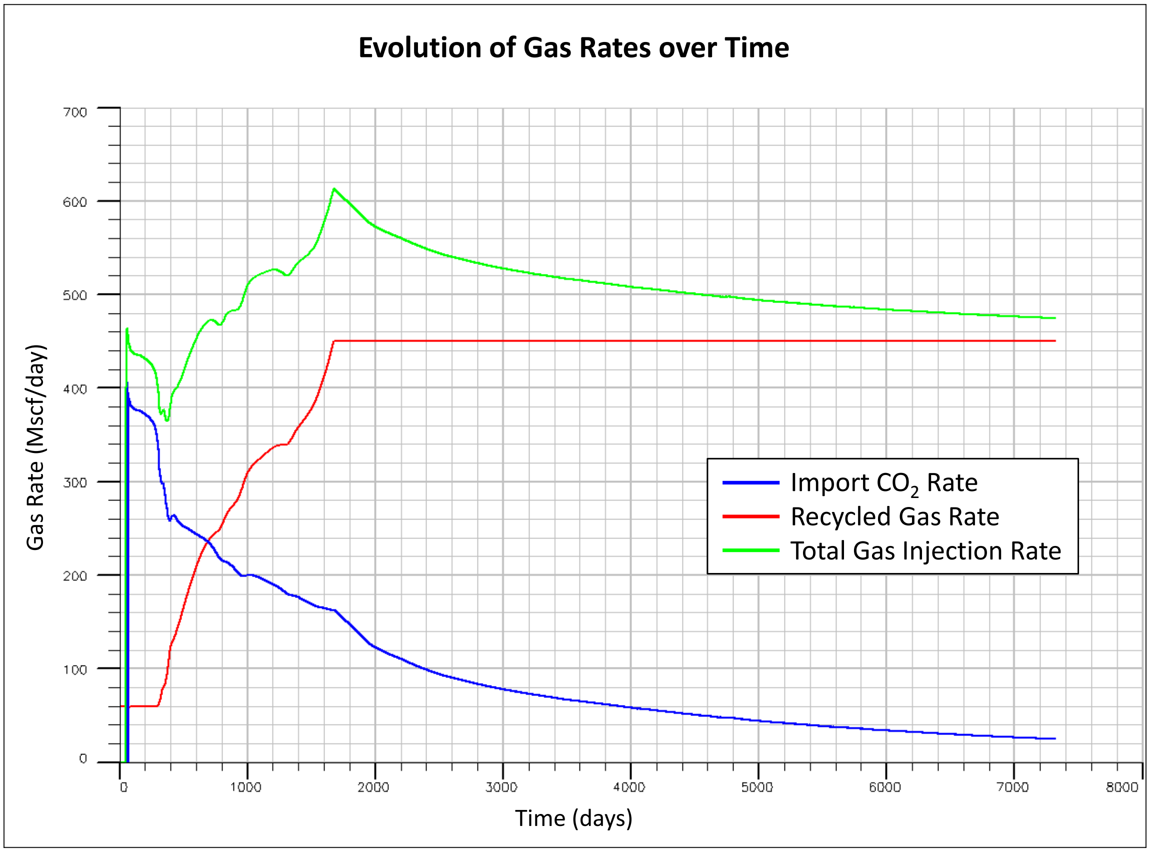

Figure 31: Evolution of the different gas rates over time in the Reference Case

CHAPTER V

DEVELOPMENT OF ALTERNATIVE STRATEGIES

V.1. Overview of the Alternative Strategy

As we showed in the previous chapter, there is a need for a more sophisticated injection strategy, where the import CO_2 rate is more constant over time.

The strategy of not letting the reservoir pressure fall below the Minimum Miscibility Pressure can be discussed as well. As it is true that CO_2 is only miscible in the oil in static conditions above that pressure, it does not take into account the dynamic effects that will favor miscibility. Therefore, it is possible to drop the reservoir pressure below the Minimum Miscibility Pressure while ensuring CO_2 miscibility.

V.1.1. Main Principle

The main strategy is to re-use the constraints on the maximum production rates found in CHAPTER IV, and to adapt the injection controls. It is possible to modify the injection trigger, the total injection rate, and the import CO_2 rate.

The strategy will be the following: production starts with a natural depletion phase. Once the field pressure reaches a given pressure (this parameter will be optimized), import CO_2 injection is triggered. The injector is controlled by import CO_2 rate: it reinjects all the gas produced, and adds import CO_2 at a controlled rate. Adding this import gas will ultimately raise the reservoir pressure. It is therefore necessary to add a pressure cap at the injector: when the initial reservoir pressure is reached, the injector control mode switches to a Bottom Hole Pressure control. From that point forward, the import CO_2 rate is adjusted to maintain the pressure at the initial reservoir pressure.

This strategy will solve the problem of the decreasing import CO_2 rate by making it follow a plateau. It will also increase the storage capacity compared to the Reference Case since the reservoir is depleted further before injection, and the reservoir pressure is raised higher after.

V.1.2. Model Constraints

The producer constraints are the ones defined in CHAPTER IV. The aim of this chapter is to choose optimal constraints for the import CO_2 rate and the injection trigger, to have a fixed import CO_2 rate for as long as possible. The constraints are shown in Table 22.

Table 22: Model constraints for the improved strategies, showing the constraints that will be optimized in this chapter

Model Constraint	Value	Unit
Producer		
Oil Production Plateau	≥ 3	years
Maximum Oil Rate	60	stb/day
Maximum Gas Rate	450	Mscf/day
Injector		
Import CO_2 Plateau Rate	To Be Determined	Mscf/day
Injection Trigger	To Be Determined	psi
Produced gas re-injected as is		

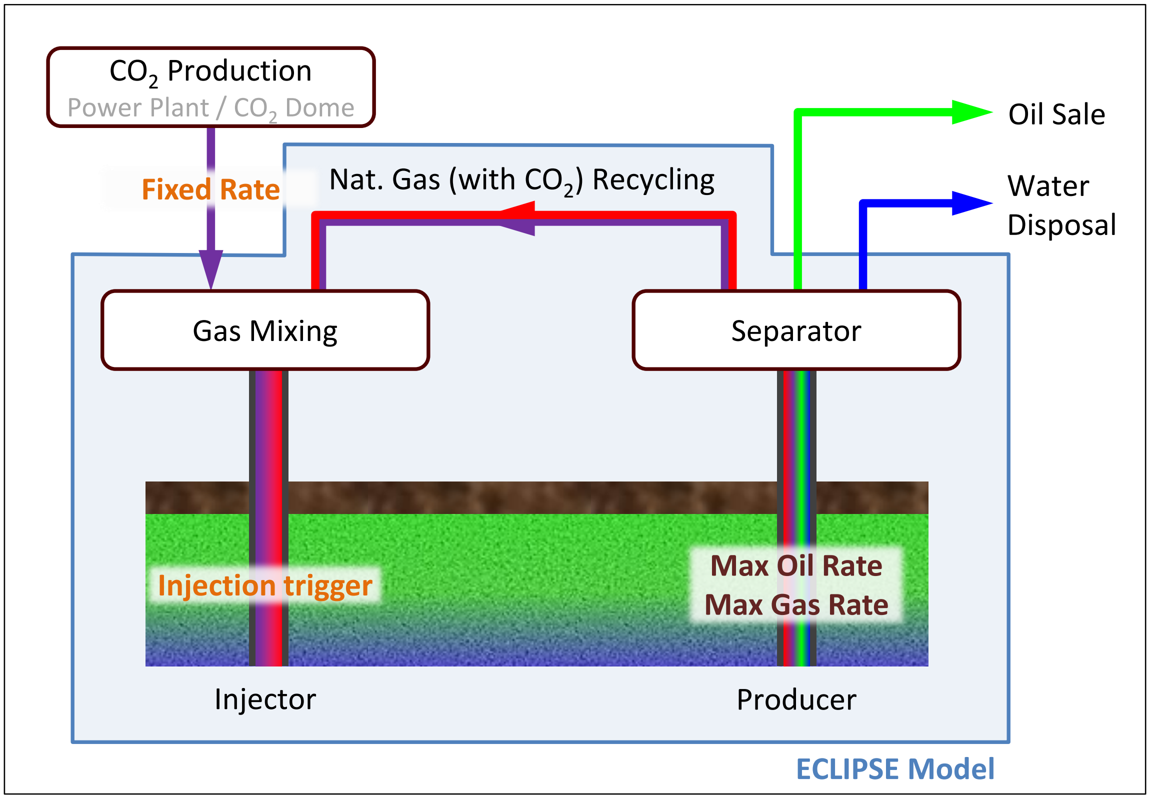

Figure 32: Overview of the main controls of the improved strategies. The fixed controls (producer) are in brown, the controls to be optimized are in orange

V.1.3. Typical Behavior

With this updated strategy, there will be a plateau for the import CO_2 rate. From an industrial perspective, this makes it more realistic and prone to happen than the Reference Case. This plateau will last from the moment the injection is triggered until the initial reservoir pressure is reached. At this moment, the import CO_2 rate will be reduced and controlled to maintain the bottomhole pressure of the injector at this value.

The length of the import CO_2 plateau depends on both the CO_2 import rate and the injection trigger. The influence of the CO_2 import rates is illustrated on Figure 33. It clearly shows that the duration of the import CO_2 plateau decreases when the import CO_2 rate increases. Similarly, the influence of the injection trigger is illustrated on Figure 34. It shows that the duration of the import CO_2 plateau increases when the injection trigger decreases.

The aim of this chapter is to determine the optimal set of injection constraints.

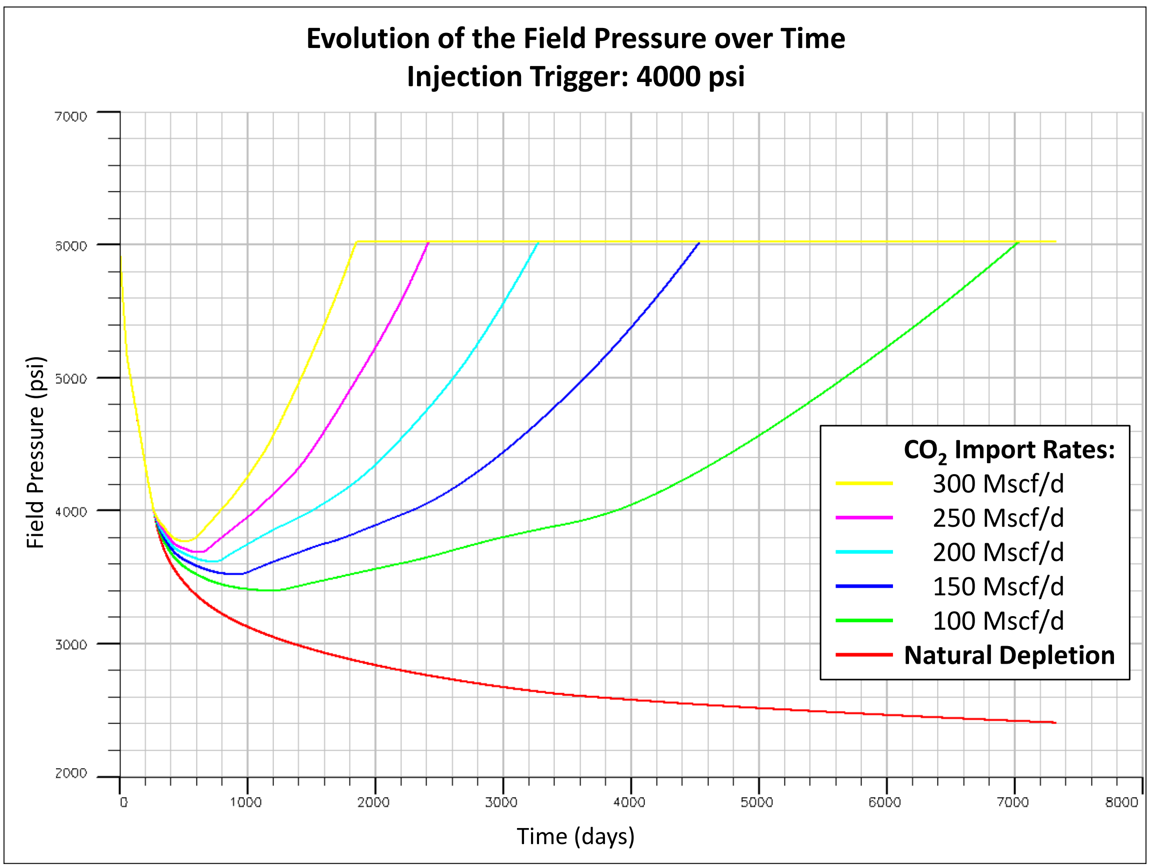

Figure 33: Evolution of the field pressure for a given injection trigger (4000 psi) and several CO_2 import rates. The imported CO_2 plateau lasts until the initial field pressure is reached

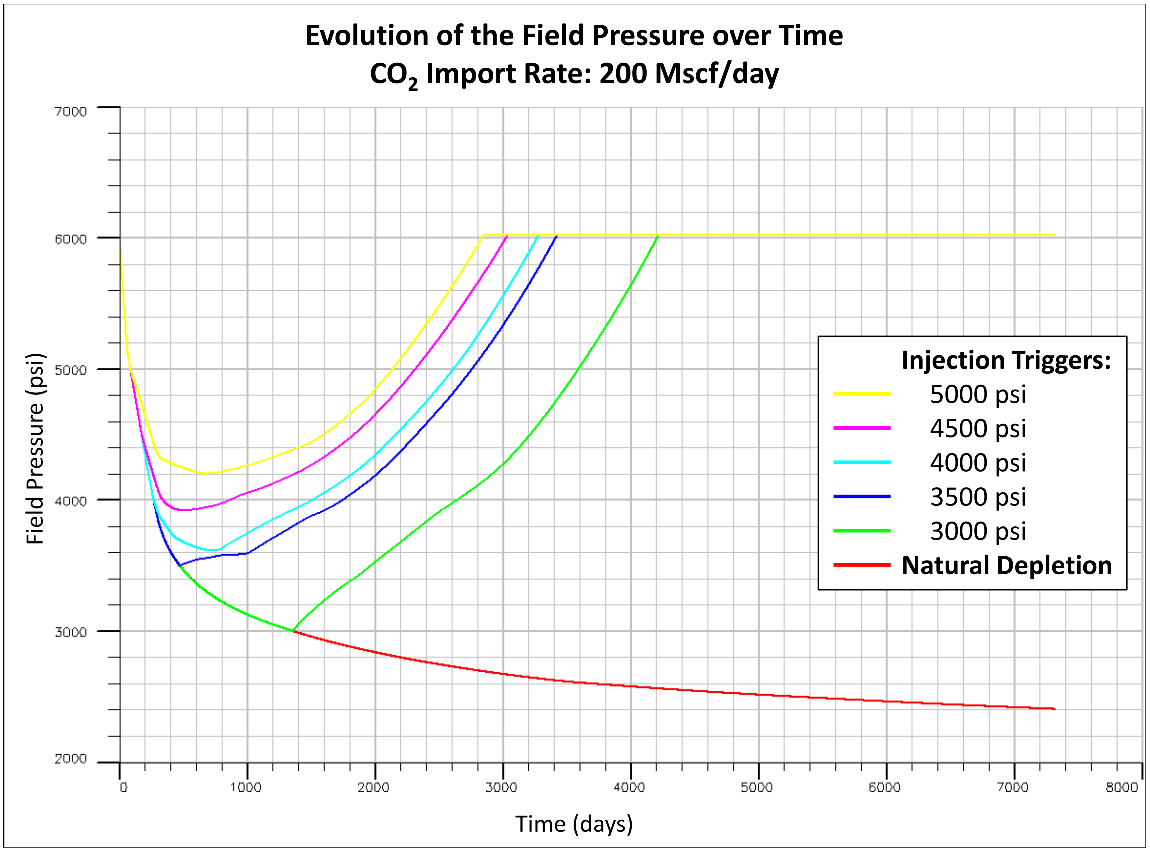

Figure 34: Evolution of the field pressure for a given CO_2 import rate (200 Mscf/day) and several injection triggers. The imported CO_2 plateau lasts until the initial field pressure is reached

V.2. Sensitivity Analysis to the Injection Constraints

V.2.1. Conducted Runs

Runs have been carried out with the following set of injection constraints:

- CO_2 import rate: 100 to 300 Mscf/day, every 50 Mscf/day
- Injection trigger: 3000 to 5000 psi, every 500 psi

These values of the injection trigger are proposed because they lie between the injection trigger of the Reference Case (5200 psi) and the ultimate reservoir pressure that occurs if the field is produced only by natural depletion (2400 psi).

All economic data remains the same as in the Reference Case, except that for these runs the pipeline is designed to handle 100% of the import of CO_2. Indeed, these cases are designed to have a stable CO_2 supply over a long period of time. Therefore, it would be counterproductive to transport part of the plateau production by trucks.

V.2.2. Screening Criteria Selection

For these optimization runs, it is necessary to consider additional screening criteria, compared to the Reference Case. First, the duration of the import CO_2 plateau is an important criterion: the main goal of this chapter is to make it as long as possible. Second, economic criteria must also be considered. The reason is that with these schedules, oil production will be delayed in time. As a consequence, a project with a better recovery may not be better, in terms of economics. Therefore, the Internal Rate of Return (IRR) and net Present Value discounted at 10% (PV10) have been considered as screening criteria.

Finally, the maximum gas-oil ratio during the oil production plateau is not considered as a relevant criterion for these models, first because using too many criteria makes the selection inaccurate or even impossible, and second because the drawbacks associated to high gas-oil ratios (higher cost of gas recycling, lower oil production and therefore lower revenue) are accounted for in the economic measures.

The retained screening criteria are presented in Table 23.

Table 23: Screening criteria for the alternative scenarios

	Screening criteria	**Unit**	**Target**
1	Oil Production Plateau Duration	years	Must be ≥ 2.5 years
2	Import CO_2 Plateau Duration	years	Maximum, should be ≥ 7 years
3	Total Oil Production	STB	Maximum
4	Total CO_2 Imported	Mscf	Maximum
5	Net Present Value @ 10%	$	Maximum, must be > 0
6	Internal Rate of Return	%	Maximum, must be ≥ 10%

The import CO_2 plateau duration should be larger than 7 years (1/3 of the project duration), if possible. The hurdles used for the PV10 and the IRR are the ones commonly used in the industry: the PV10 must be positive, and the IRR must be larger than 10%.

The detailed results of these screening criteria for each run can be found in APPENDIX 8.

V.2.3. Results of the Screening Criteria

a. Oil Production Plateau Duration Results

For the analysis of these modified schedules, the oil production plateau must be redefined, because it can be split in two parts: it will be sustained for a period of time during the natural depletion phase, until the reservoir pressure is not sufficient to sustain it. When CO_2 injection starts, the pressure support can be sufficient for the oil production to reach back to the plateau rate (Figure 35). The oil production plateau rate is therefore redefined as the period of time during which the field produces at the maximum oil rate.

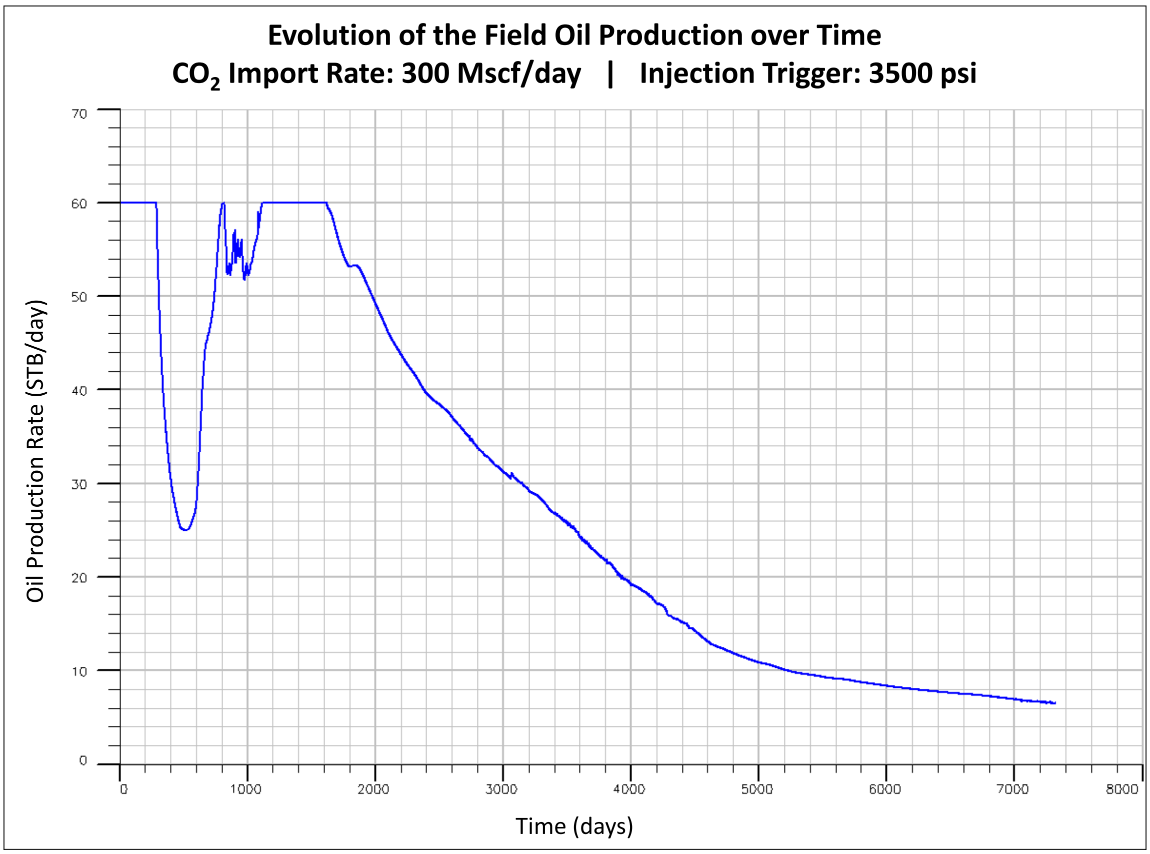

Figure 35: Evolution of the oil production rate for a CO_2 import rate of 300 Mscf/day and an injection trigger at 3500 psi

The results for the oil production plateau duration are presented in Figure 36. One can observe that only the red area represents oil production plateaus longer than 3 years

(Figure 36). As a consequence, as this is an absolute criterion, only a few combinations of the injection trigger and import CO_2 rate remain possible. They correspond to the red area in Figure 37. The oil production plateau is scaled as a quantitative criterion from 0 to 1 the same way as in IV.2.2.a.

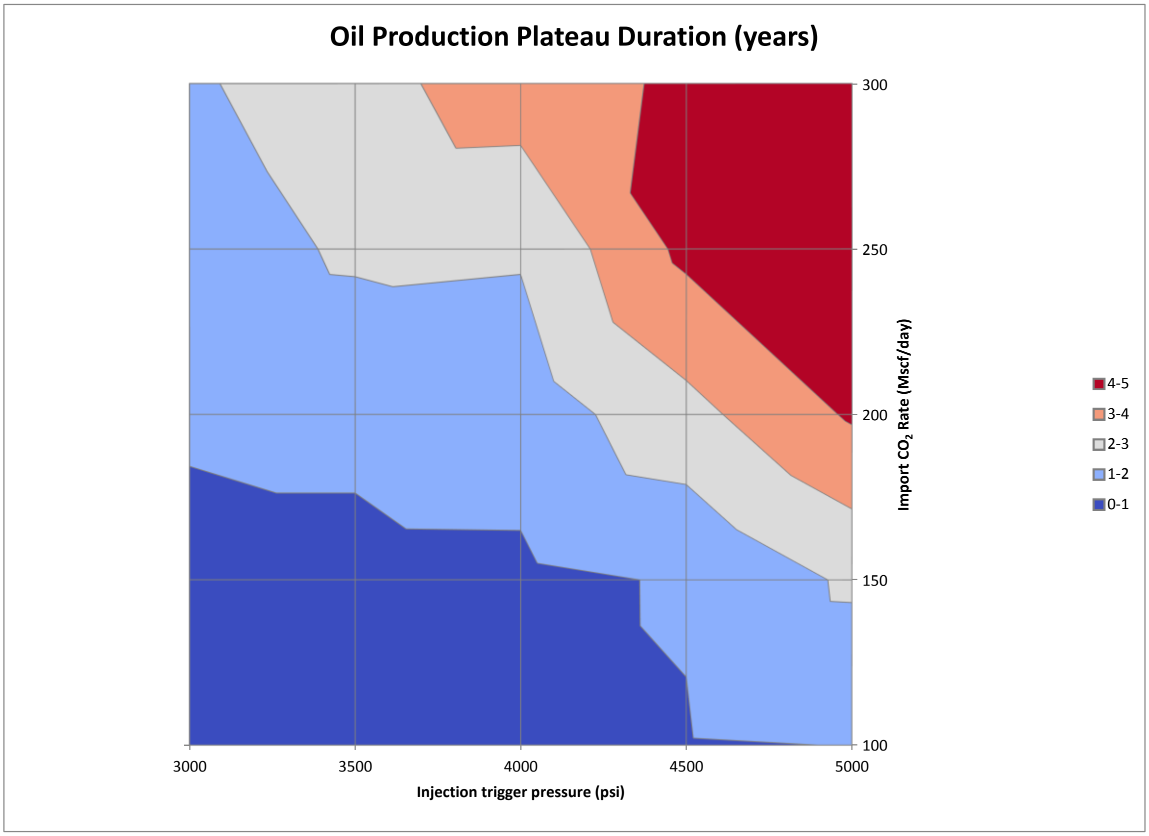

Figure 36: Oil production plateau duration for the two injection constraints

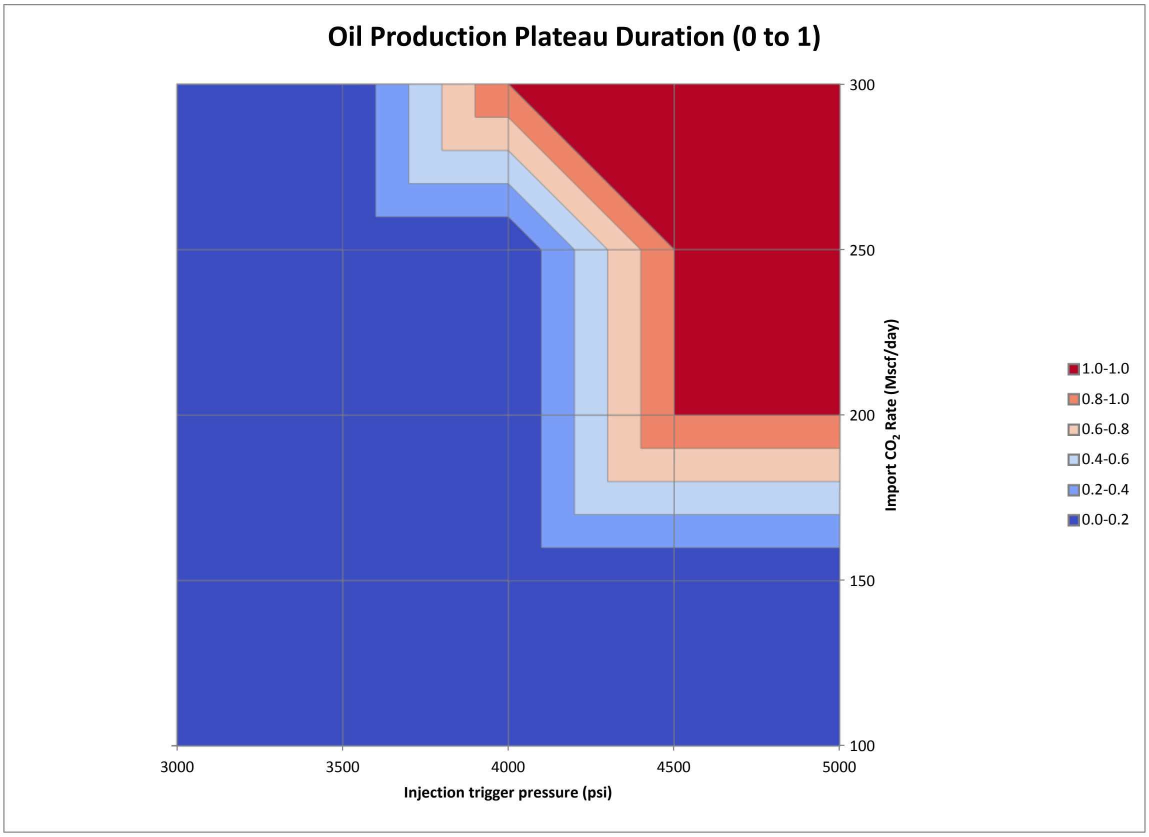

Figure 37: Oil production plateau duration for the two injection constraints, scaled from 0 (duration lower than 3 years) to 1 (duration higher than 3 years)

b. Import CO_2 Rate Plateau

The duration of the import CO_2 rate plateau is quite good for all the runs, with a minimum of 3.5 years. For more than 60% of them, it is 7 years or higher (Figure 38). It is scaled from 0 to 1 using the following rules:

- Linear interpolation from 0 years (value 0) to 7 years (value 1)
- Value 1 if it is higher than 7

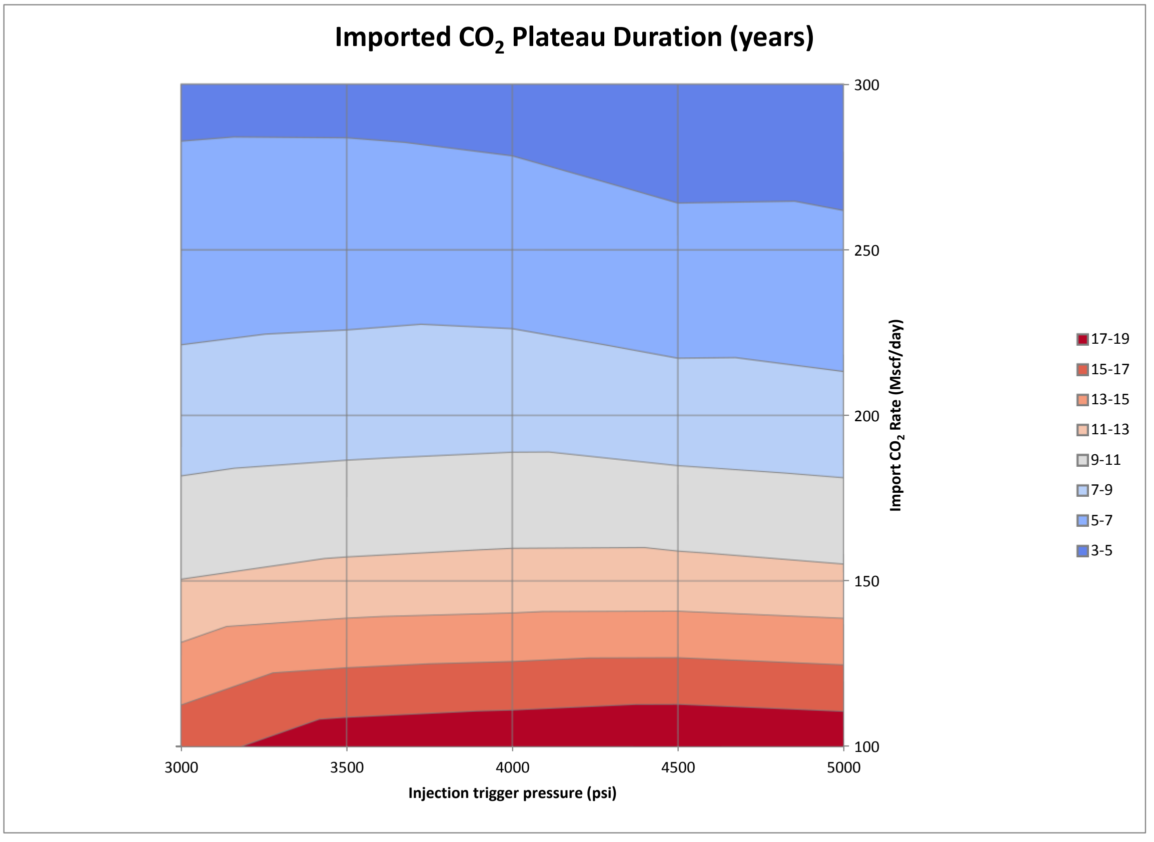

Figure 38: Duration of the imported CO_2 plateau for all the runs

c. Total Oil Production

The total oil production for the different injection constraints is shown in Figure 39. It is interesting to notice that the total production is never higher than for the Reference Case: the maximum value obtained here is 226,982 STB (for an import CO_2 rate of 300 Mscf/day and an injection trigger at 5000 psi), versus 231,236 STB STB for the Reference Case. This corresponds to a loss of at least 1.8% of the oil recovery compared to the Reference Case. The total oil production is scaled as a quantitative criterion from 0 to 1 the same way as in IV.2.2.b.

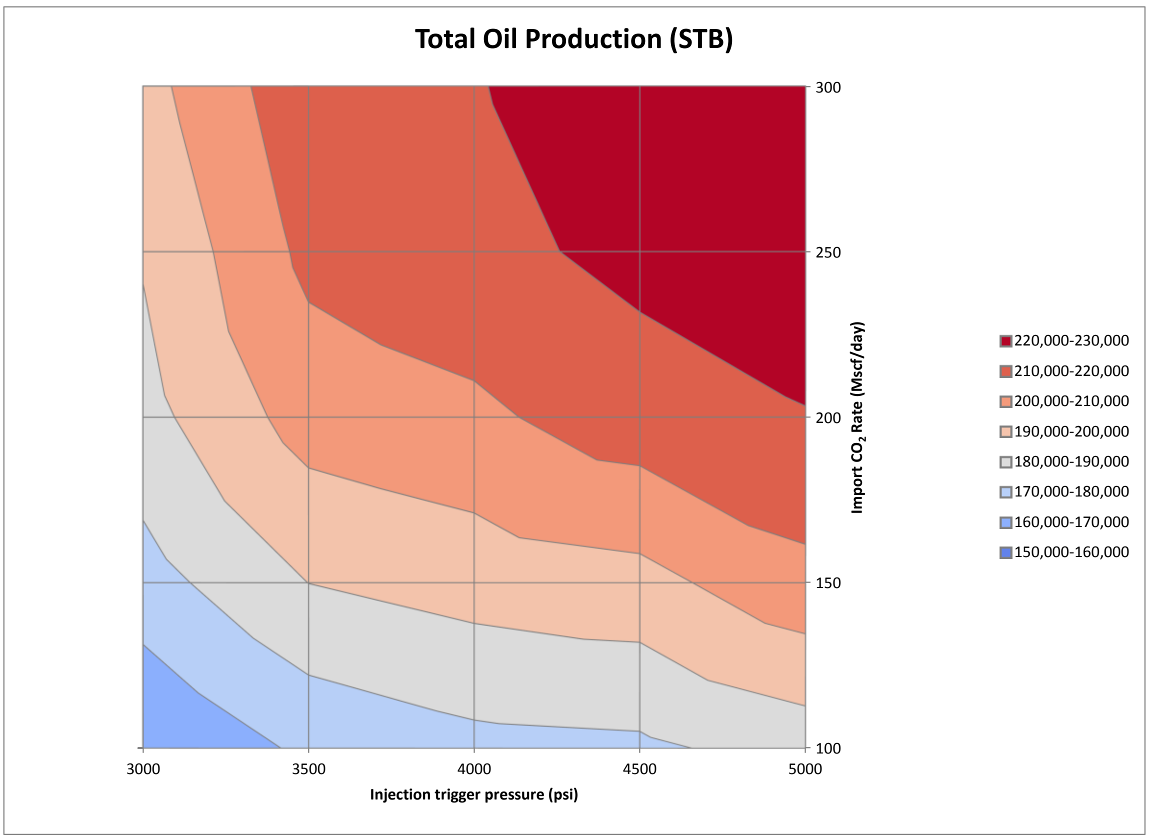

Figure 39: Total oil production for all the runs

d. Total CO_2 Imported

The total CO_2 imported for all the combinations of injection constraints is shown in Figure 40. For 18 runs (72%), the total CO_2 imported is larger than in the Reference Case. The maximum, 788,975 Mscf (for an import CO_2 rate of 300 Mscf/day and an injection trigger at 4000 psi) represents an increase of 9.8% compared to the Reference Case, where 718,430 mtons of CO_2 are imported. It is interesting to notice that the total CO_2 imported does not vary significantly with the injection trigger, apart from the lowest value. The total CO_2 imported is from 0 to 1 the same way as in IV.2.2.c.

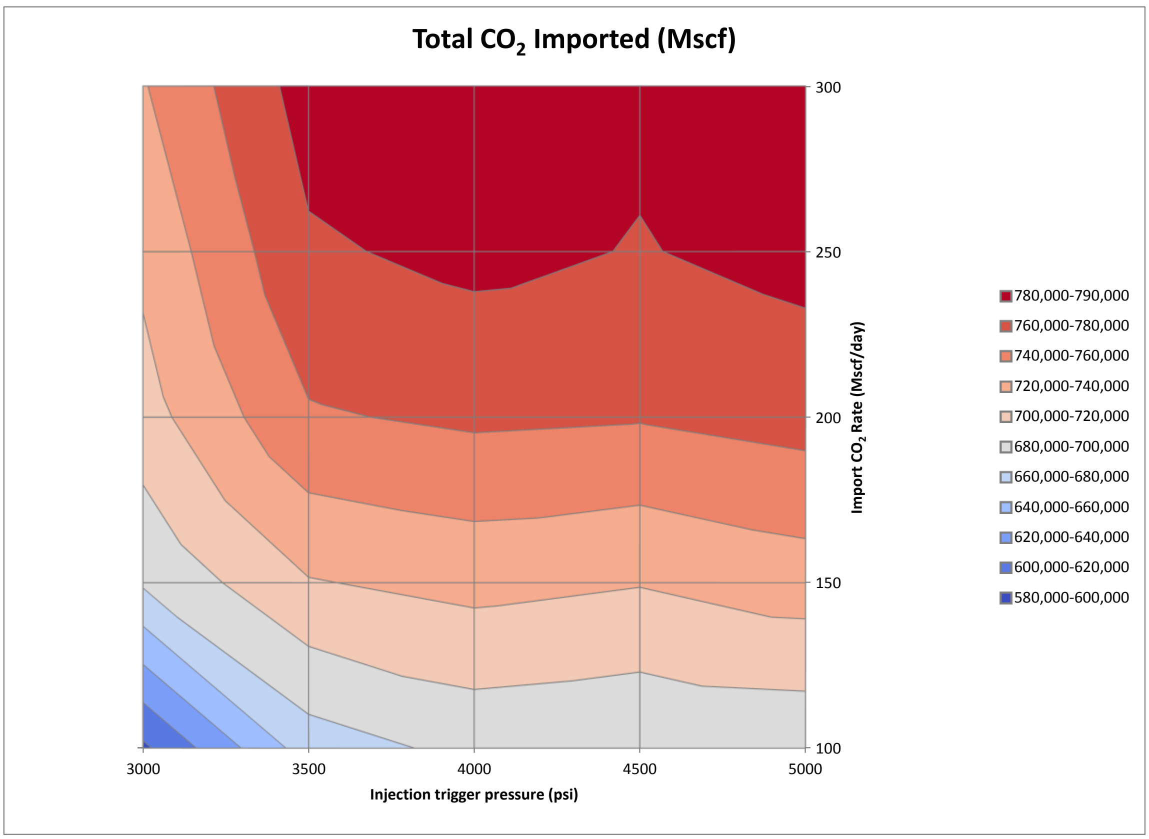

Figure 40: Total CO_2 imported for all the runs

e. Net Present Value Discounted at 10%

The Net Present Value discounted at 10% for all the combinations of injection constraints is shown in Figure 41. In all the runs, the PV10 is lower than for the Reference Case. The maximum PV10 obtained, 829 MM$ (for an import CO_2 rate of 250 Mscf/day and an injection trigger at 4500 psi) represents a 3.5% loss compared to the Reference Case, that has a PV10 of 858 MM$. The PV10 is scaled as a quantitative criterion from 0 to 1 by assigning 0 to a negative PV10, and linearly interpolating from 0 to 1 between 0$ and the maximum PV10 encountered.

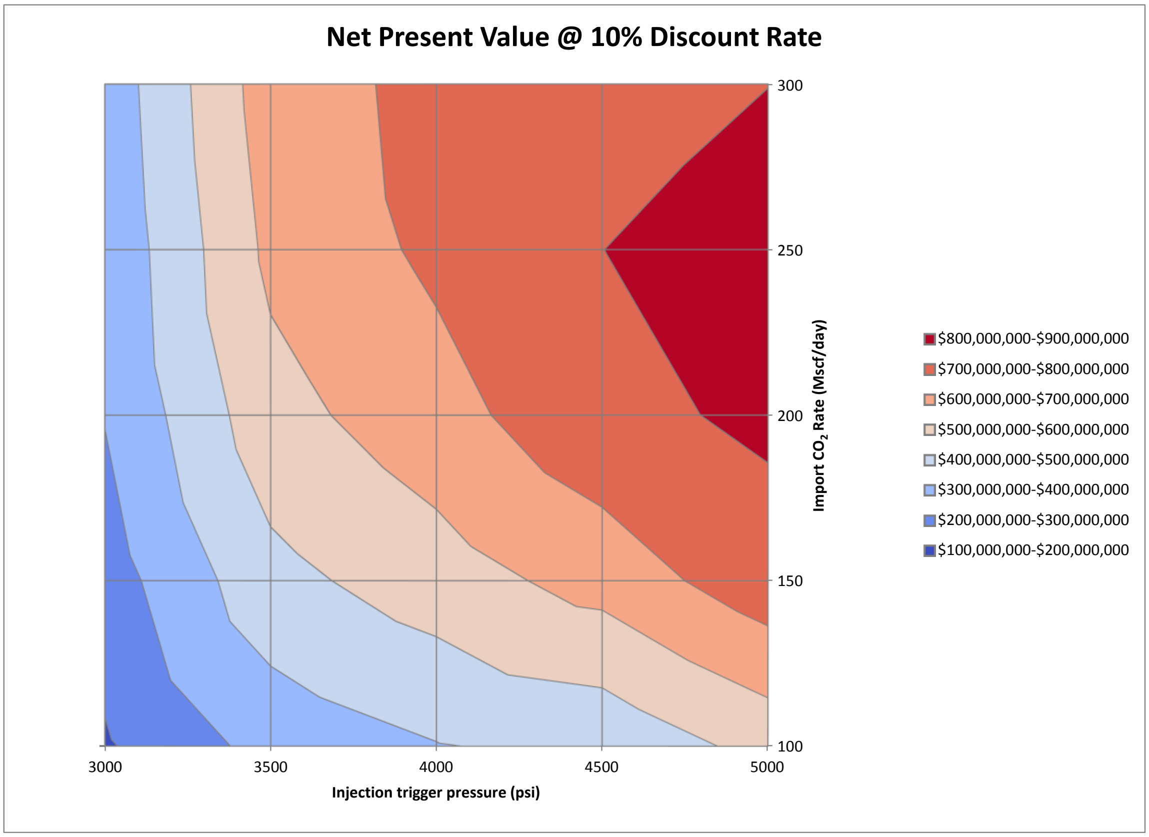

Figure 41: Net Present Values discounted at 10% for all the runs

f. Internal Rate of Return

The Internal Rate of Return for all the combinations of injection constraints is shown in Figure 42. In 10 runs (40%), the IRR is higher than for the Reference Case. The maximum IRR obtained, 51.2% (for an import CO_2 rate of 150 or 200 Mscf/day and an injection trigger at 5000 psi), represents a gain of 16.1% over the Reference Case, that has an IRR of 44.1%. The IRR is scaled as a quantitative criterion from 0 to 1 by assigning 0 to an IRR less than 15% (hurdle rate), and linearly interpolating from 0 to 1 between 15% and the maximum IRR encountered.

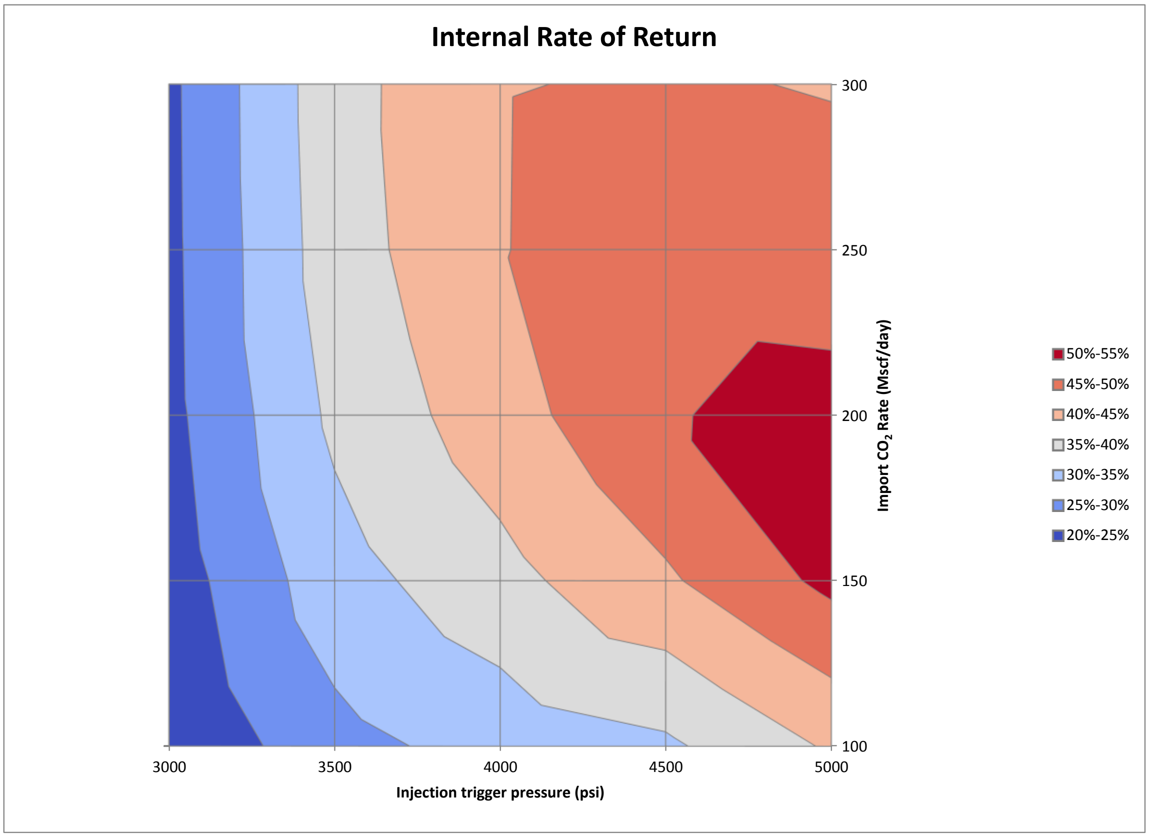

Figure 42: Internal Rate of Return for all the runs

V.3. Optimal Constraints for the Injection Parameters

All the screening criteria scaled from 0 (bad) to 1 (good) are shown on Figure 43.

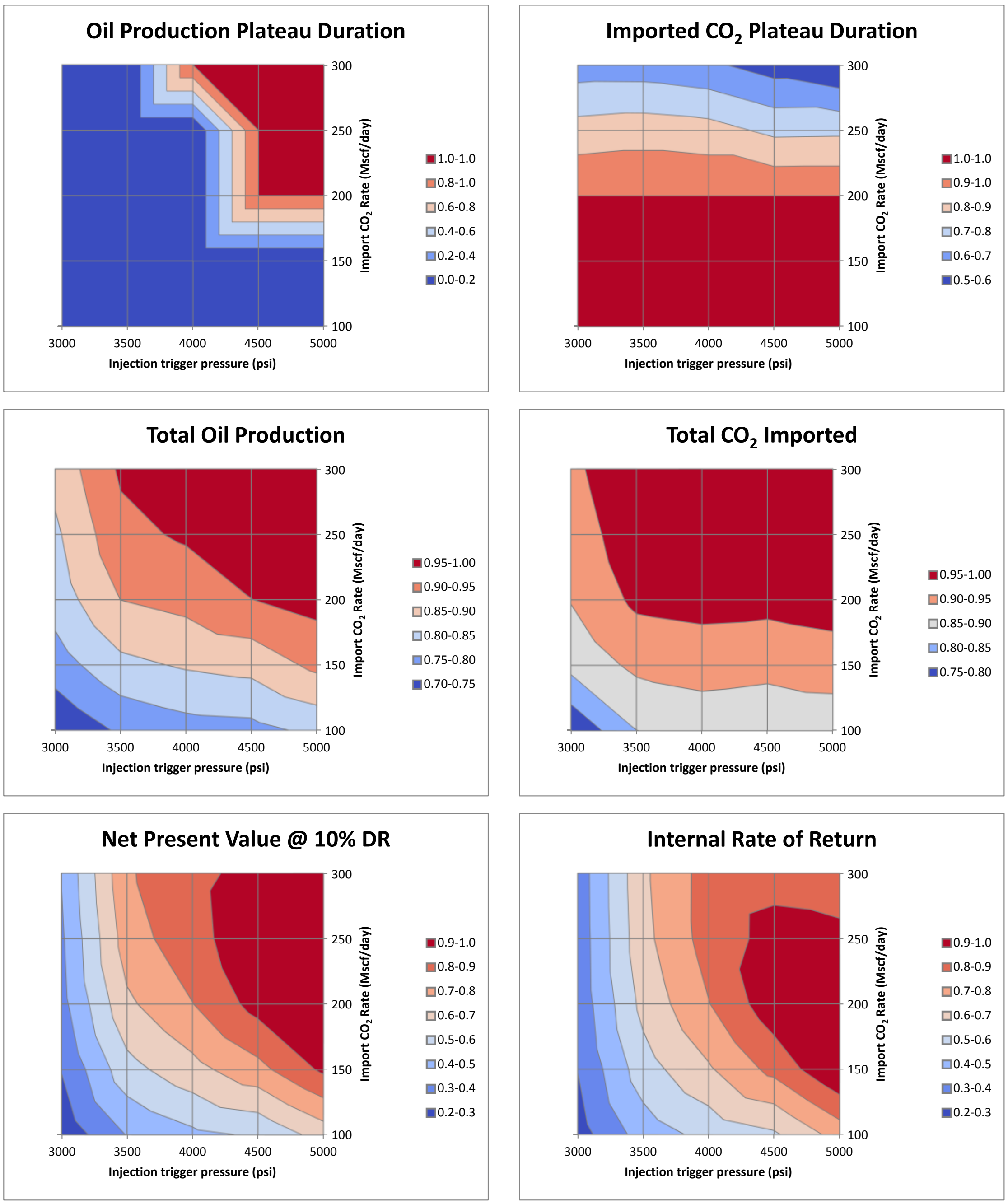

Figure 43: All screening criteria for the improved strategies scaled from 0 to 1

All these screening criteria are combined into one synthetic chart, shown on Figure 44.

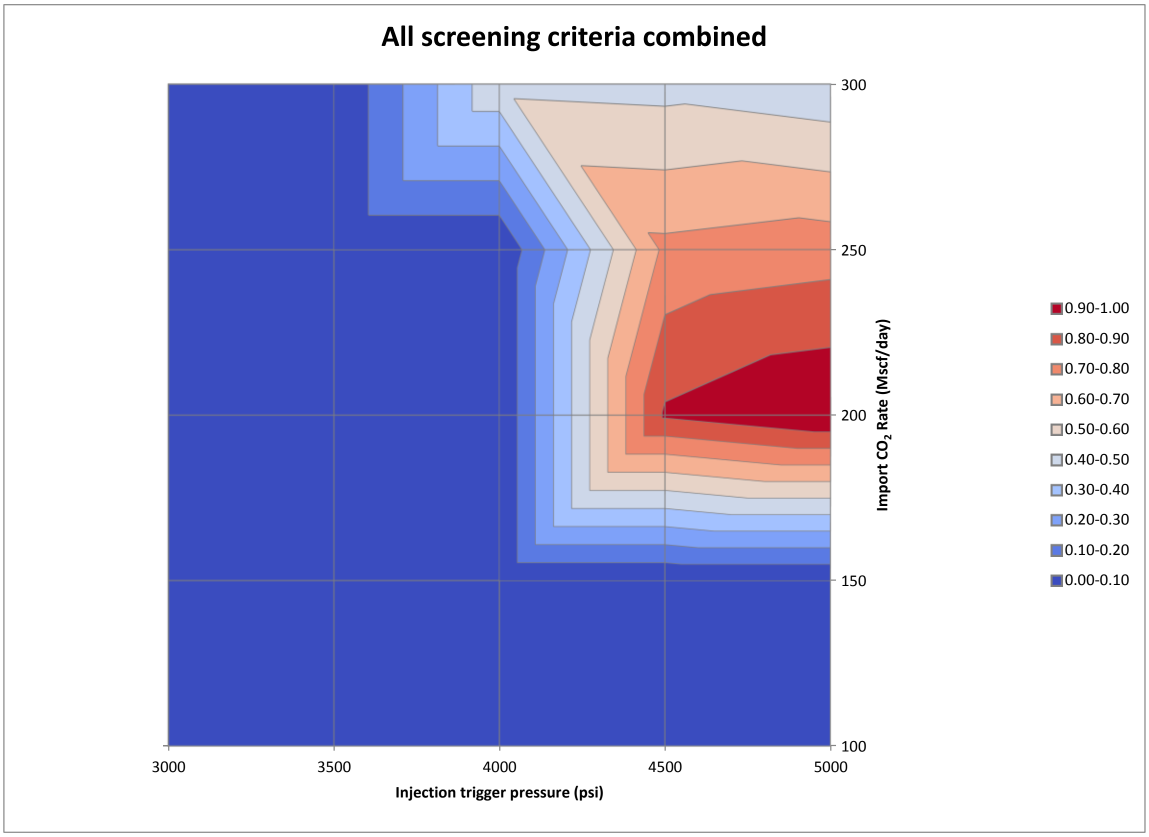

Figure 44: All screening criteria of the optimized runs combined

The red area represents the “hot” zone, i.e. the area where the model constraints should be picked to optimize the chosen criteria. This “hot” zone is very narrow, and encloses only 2 of the runs: an import CO_2 plateau rate of 200 Mscf/day, combined with an injection trigger of 4500 psi (Run 1) or 5000 psi (Run 2). The screening criteria for the base case and these 2 runs are presented in Table 24.

Table 24: Screening criteria for the Reference Case and the selected optimized runs

Screening Criteria	Reference	Run 1	Run 2	Unit
Oil production plateau duration	4.6	2.7	4.1	years
Import CO_2 plateau duration	-	7.8	7.6	years
Total oil production	231,236	215,520	219,637	STB
CO_2 imported	718,430	761,472	767,638	Mscf
Net Present Value @ 10%	858	778	815	MM$
Internal Rate of Return	44.1	49.8	51.2	%

Run 2 is superior to run 1 for all the criteria except the import CO_2 plateau duration, which is still long enough (longer than 1/3 of the project) for run 2. It is therefore these injection constraints that are chosen as optimal.

The updated set of constraints for the alternative injection strategies is therefore given in Table 25.

Table 25: Chosen constraints for the alternative injection strategies

Model Constraint	Value	Unit
Producer		
Oil Production Plateau	≥ 3	years
Maximum Oil Rate	60	stb/d
Maximum Gas Rate	450	Mscf/d
Injector		
Import CO_2 Plateau Rate	200	Mscf/d
Injection Trigger	5000	psi
Produced gas re-injected as is		

V.4. Overview of the Alternative Strategy

The alternative strategy considered a lower injection trigger (5000 psi) than for the Reference Case (5200 psi). From this lower injection trigger, imported CO_2 is injected at a given plateau rate (200 Mscf/day) until the initial reservoir pressure is reached. At this moment, the imported CO_2 rate is adapted to maintain this pressure.

Some injection and production metrics for the Reference Case and the Alternative Case are given in Table 26. They show that the alternative strategy decreases the oil recovery, but increases the amount of CO_2 stored.

Table 26: Value of the screening criteria for the Reference Case and the Alternative Case

Parameter	Reference Case	Alternative	Unit	Variation
Oil production plateau	4.6	4.1	years	- 10.9%
Import CO_2 plateau	-	7.6	years	-
Oil recovered	231,236	219,637	STB	- 5.0%
Recovery factor	74.9	71.2	%	- 5.0%
CO_2 imported	718,430	767,638	Mscf	+ 6.8%
	37,800	40,400	mtons	+ 6.8%
Storage density	18.1	19.4	lb/ft^3	+ 6.8%

As previously stated, the 2 projects have to be ranked looking at economic criteria. Some economic measures are listed in Table 27. They show that even though the NPV of the alternative case is lower, its IRR is higher, with a shorter payout. This can be explained by the fact that the initial investment is lower in the Alternative Case, and so are the operating costs: there is no cost for importing CO_2 during the early natural depletion case, and the cost of transport by trucks is avoided. Moreover, the pipeline capacity is better used.

Table 27: Some economic metrics for the Reference Case and the Alternative Case

Parameter	Reference Case	Alternative	Unit	Variation
Initial Investment	551	534	MM$	- 3.1%
Present Value @ 10%	858	815	MM$	- 5.0%
Internal Rate of Return	44.1	51.2	%	+ 16.1%
Profitability Index @ 10%	2.55	2.52	-	- 1.2%
Payout (undisc.)	27	22	months	- 18.5%
Technical cost (undisc.)	41.16	41.86	$/STB	+ 1.7%

V.5. Conclusions

This chapter shows the validity of the approach adopted: starting from the Reference Case, an alternative strategy can be developed and optimized that will yield a better performance regarding CO_2 storage, and economic results as good as the Reference Case's, even though the final oil recovery is lower.

It also shows that the Reference Case was already well chosen: the optimized Alternative Case yields better results, but most of the other solutions tried were not as good.

V.6. Further Improvements

A path to optimize the schedule even more could be to alternate CO_2 injection periods with natural depletion periods, with a fixed imported CO_2 injection rate. If this schedule is chosen, it needs to be optimized to make sure that the end of the project coincides with the end of an injection cycle, to make sure that the amount of CO_2 stored is maximized.

This strategy is illustrated in Figure 45, where the cycles of natural depletion followed by import CO_2 injection are clearly visible.

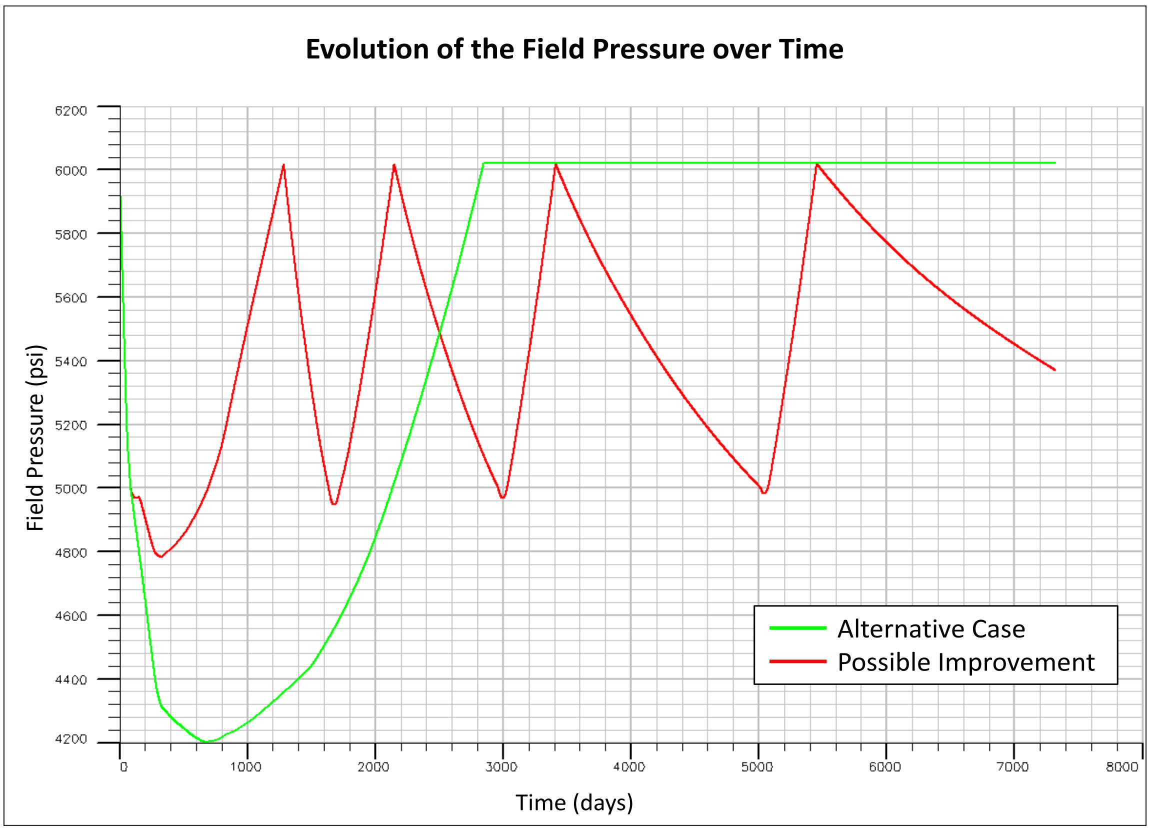

Figure 45: Evolution of the field pressure for the Alternative Case and a possible improvement (same injection trigger, import CO_2 plateau rate 300 Mscf/day)

CHAPTER VI

INFLUENCE OF AQUIFER SUPPORT ON CO_2-EOR

The impact of aquifers can be significant on oil recovery as well as CO_2 storage capacity. Bachu et al. (2004) showed that the CO_2 storage capacity can be reduced by roughly half if the considered reservoir has a strong aquifer support, if CO_2-EOR is implemented.

The aim of this chapter is to evaluate the impact of some key parameters on the CO_2 storage capacity, the oil recovery and the economics. The influence of aquifer size, wells completion, maximum allowable water cut and injection start have been studied. All the runs are based on the Reference Case defined in CHAPTER IV, with some parameters modified to assess the sensitivities to the previous parameters.

VI.1. Aquifer Models

The aquifers are modeled explicitly by adding 10 layers below the reservoir, with different heights depending on the desired aquifer size (see Figure 46). The aquifer size is expressed as a multiple of the reservoir Pore Volume (PV). The layers heights of the aquifer are progressive to avoid border effects, as shown in Table 28.

Table 28: Thicknesses of the aquifer layers (feet) for all the aquifer sizes used

	1 PV	3 PV	5 PV	10 PV	30 PV	50 PV	100 PV
1	10	10	10	10	10	10	10
2	10	10	10	10	10	10	10
3	10	10	10	13.8	42	70.1	140.6
4	10	10	15.2	31.1	94.4	157.8	316.3
5	10	15.8	27.0	55.2	167.9	280.6	562.3
6	10	24.6	42.3	86.3	262.3	438.4	878.5
7	10	35.5	60.8	124.2	377.7	631.3	1265.1
8	10	48.3	82.8	169.1	514.2	859.2	1721.9
9	10	63.1	108.2	220.8	671.5	1122.3	2249
10	10	72.7	133.7	279.5	849.9	1420.4	2846.4

The aquifers are considered as having a homogeneous horizontal permeability equal to 180.5 mD, which is the average of the reservoir horizontal permeabilities. The vertical permeability is 18.05 mD, i.e. one tenth of the horizontal permeability, like in the reservoir.

On a computational point of view, this way of modeling the aquifer is not optimal. However, it is best to use it in our case because the model is small enough not to require long computing times. Moreover, it enables the correct modeling of the interface between the aquifer and the other fluids (hydrocarbons and CO_2), even with the injection that may lower the water-oil contact.

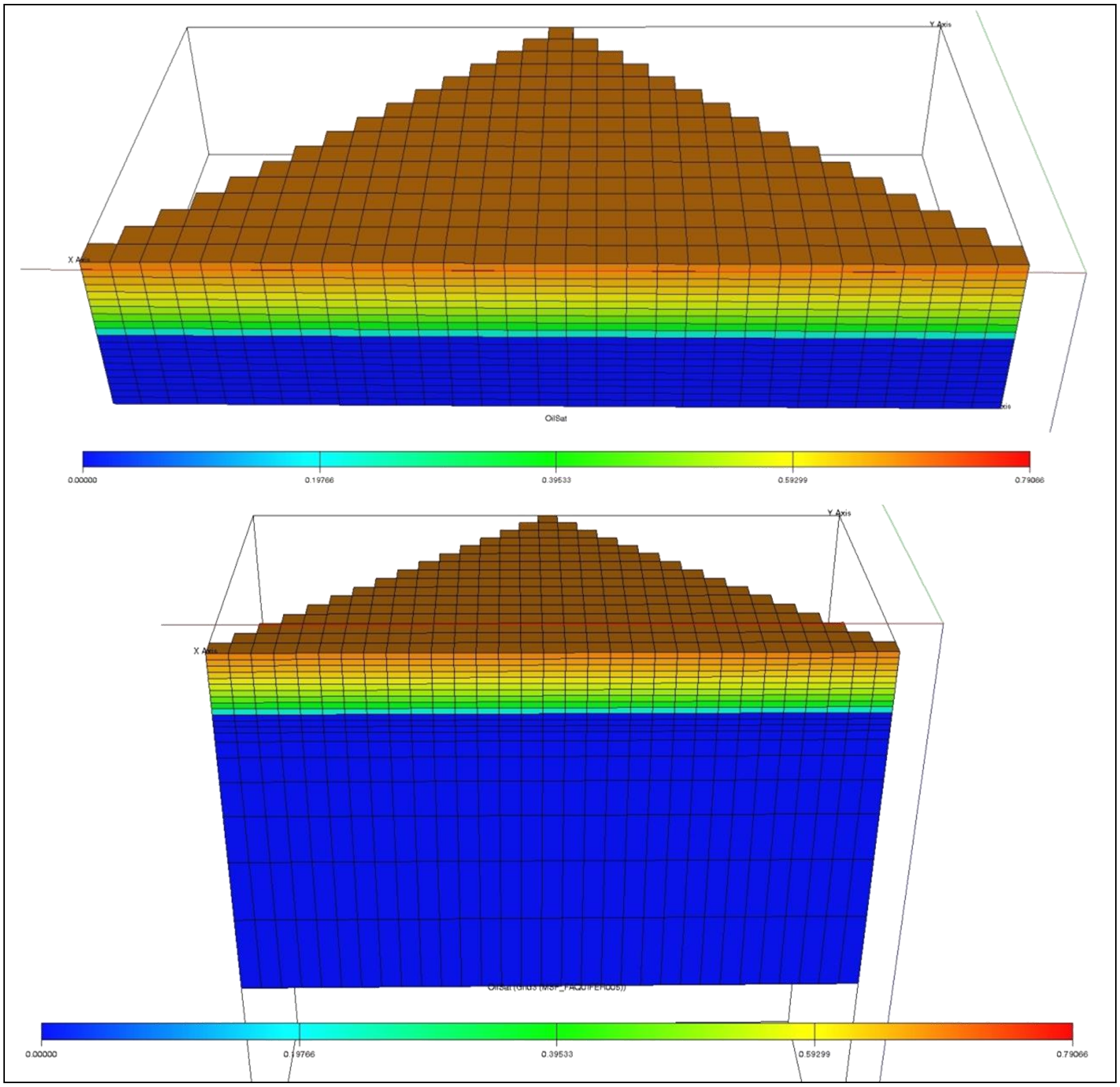

Figure 46: Aquifer models with 1 Pore Volume and 5 Pore Volume sizes. The property shown is the initial oil saturation

VI.2. Influence of the Aquifer Size

The first parameter assessed is the influence of the aquifer size. Following the recommendations of Bachu et al. (2004), fields with a cumulative Water-Oil Ratio above

0.25 STB/STB are considered as having a strong water influx. For all these aquifers, the starting Water Cut is above 0.75. Therefore, the final cumulative Water-Oil Ratio will be over that value, whatever water cut limit is imposed. All these aquifers are therefore considered as providing a strong water drive. The strength of that water drive, however, depends on the size of the aquifer, since a larger aquifer has more energy stored, available to help recovery.

VI.2.1. Production by Natural Depletion

A first run is carried out with all the aquifers by producing the reservoir only by natural depletion. No maximum water cut is imposed, which means that the wells will keep producing event though they would be stopped in a real project. The values obtained for the oil recovery are therefore upper limits. The cumulative oil productions for all the aquifer sizes are given in Figure 47.

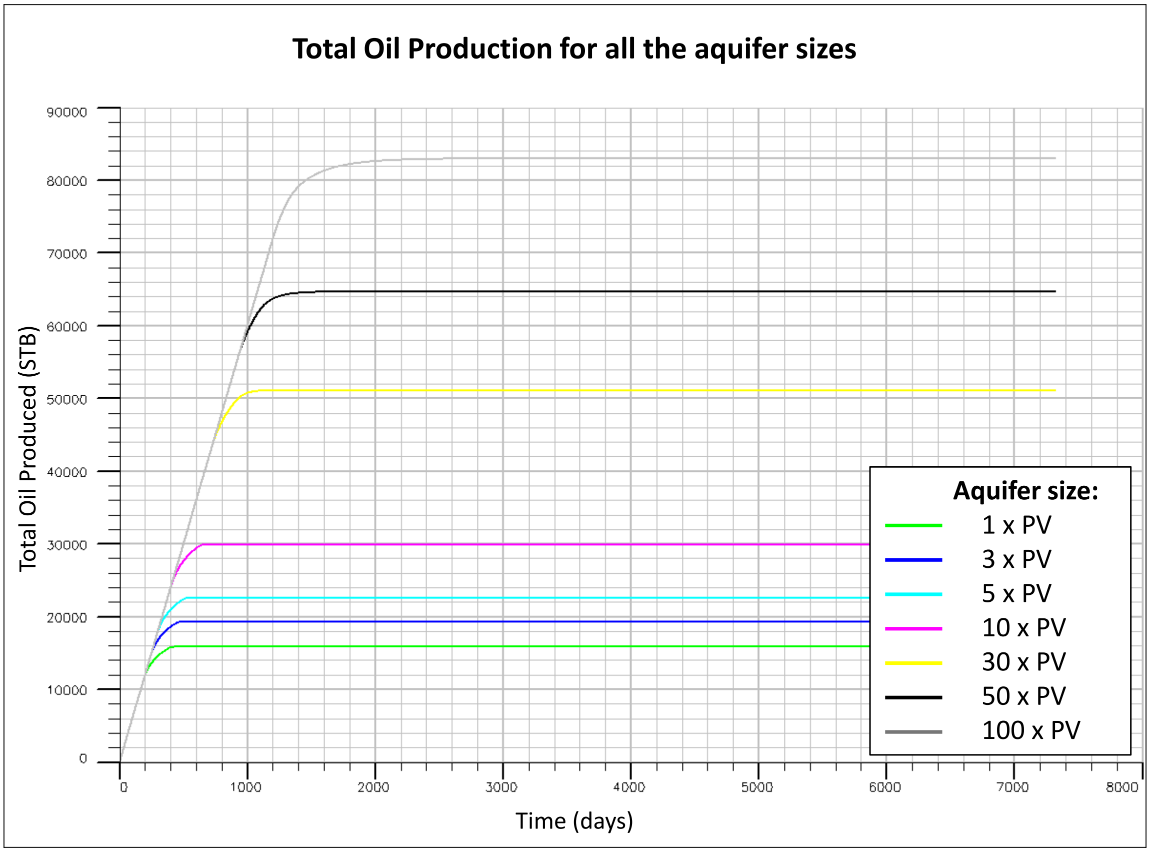

Figure 47: Cumulative oil production with natural depletion for all the aquifer sizes tested

As a comparison, the recovery in the Reference Case was 231,000 STB, versus 15,800 (1 PV aquifer) to 83,000 STB (100 PV aquifer) for natural depletion. This is a loss of 64% to 93%, and corresponds to a recovery factor of 5.1% to 26.9%. Natural depletion is therefore not the best strategy. CO_2 injection, by maintaining the reservoir pressure (in addition to its other effects on oil viscosity and residual oil saturation), can be a significant improvement.

Completing the aquifer in the upper layers is also a well-known strategy, discussed in VI.4.1.

VI.2.2. Production with CO_2-EOR

Runs have been carried out on the exact same cases as previously, improved with a CO_2-EOR process: when the injector bottom hole pressure reaches 5200 psi (the CO_2 MMP), an injection well is open. It injects a stream mixing all the produced gas, and imported CO_2. The imported CO_2 rate is adapted to maintain the injector bottomhole pressure at the MMP. The results are shown on Figure 48.

The first improvement concerns the oil recovery. With CO_2-EOR, the recoveries range from 235,000 to 243,000 STB (76.2% to 77.4% recovery factor), which is better than the base case. Moreover, the recovery values are less dispersed, because CO_2-EOR becomes the main recovery mechanism; as a secondary mechanism, the larger the aquifer, the larger the recovery. Based only on this criterion, CO_2-EOR seems to be a good strategy to increase the recovery.

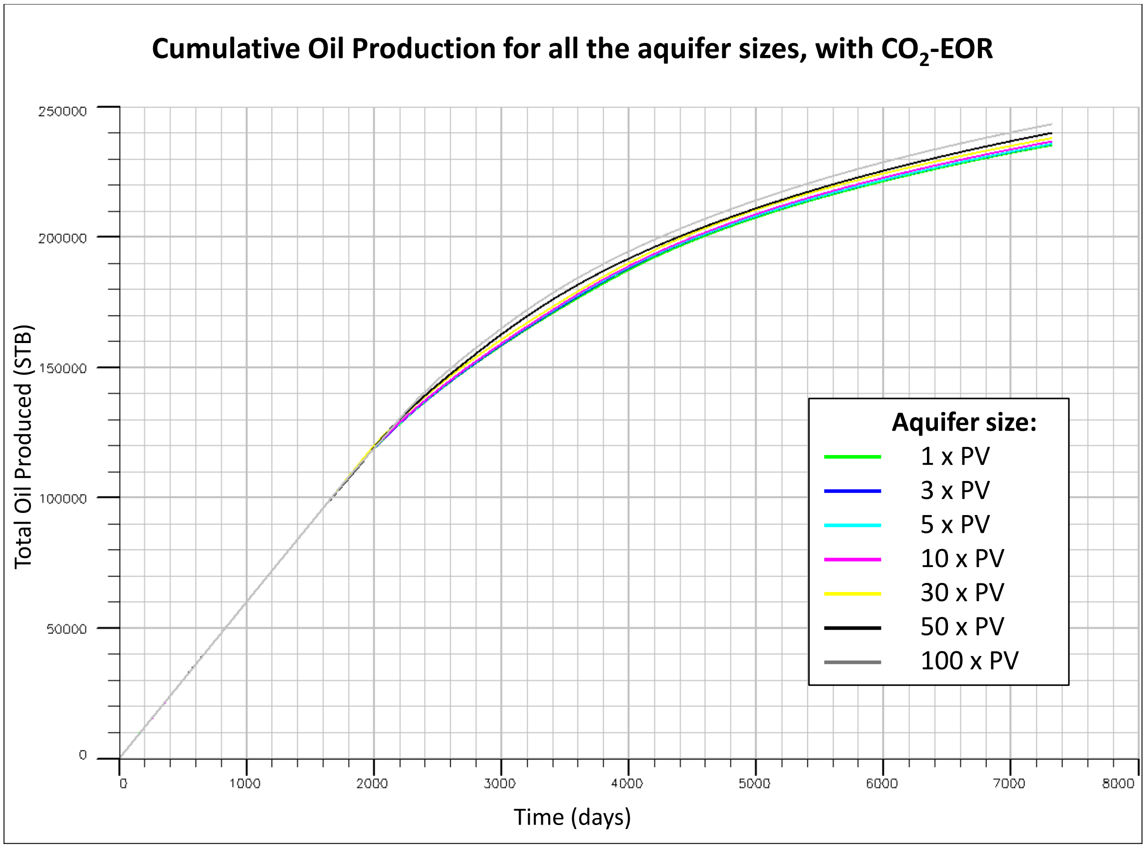

Figure 48: Cumulative oil production with CO_2-EOR for all the aquifer sizes tested

The impact on the stored CO_2 is even larger. The cumulative CO_2 imported ranges from 1,159 MMscf to 1,150 MMscf (Figure 49), versus 718 MMscf for the Reference Case. This is due to the fact that there is more volume for the pressure wave created by the injection to propagate, and that the aquifer adds additional space where CO_2 can be stored.

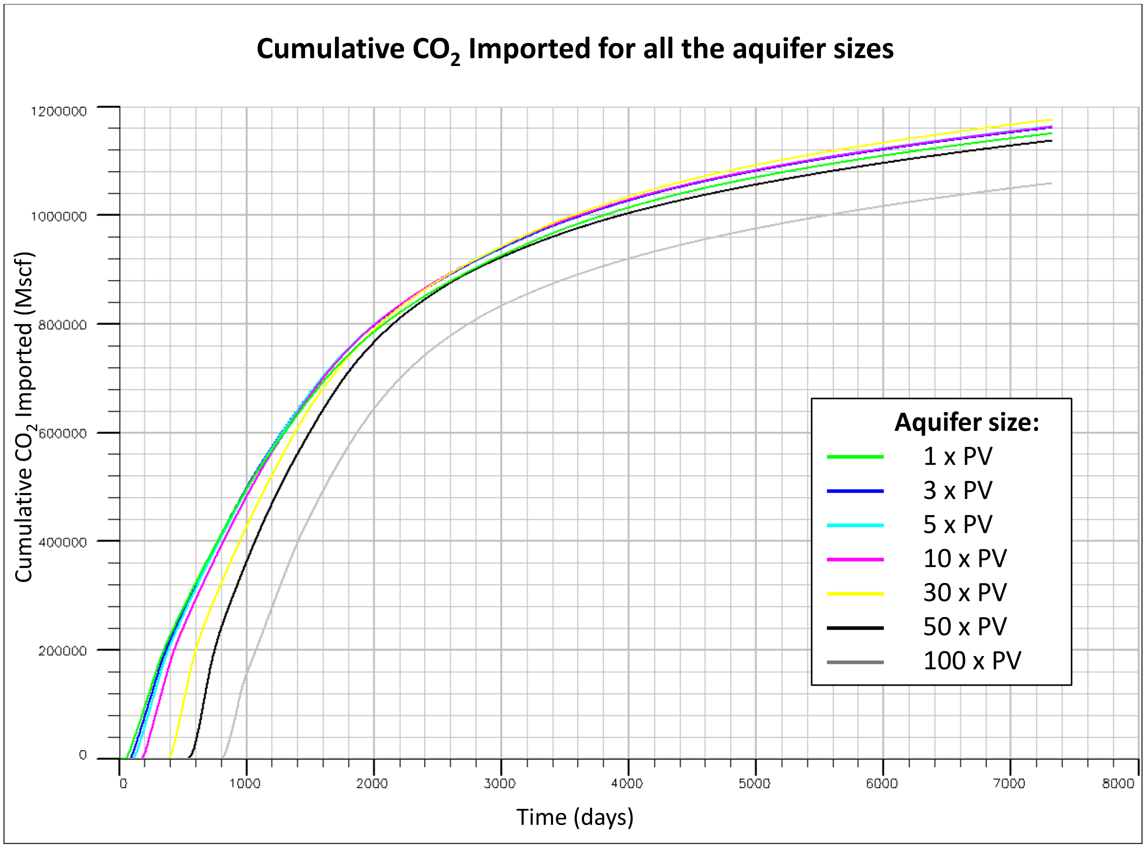

Figure 49: Cumulative CO_2 imported with CO_2-EOR for all the aquifer sizes tested

These cases theoretically show that aquifers are beneficial to CO_2-EOR. However, they do not reflect fully realistic industrial conditions. The main constraint is the water cut: as it increases, the profitability of the well decreases because the water must be treated and disposed of. Therefore, the production and injection are likely to be stopped earlier. Depending on the moment when the well is not profitable any more, it is possible that the recoveries and storage capacities obtained without accounting for a maximum water cut are highly overestimated.

VI.3. Influence of the Maximum Water Cut

The influence of the maximum water cut has been investigated in a case where the aquifer pore volume is 100 times the reservoir's pore volume. There is therefore the strongest water drive. An economic constraint is added to the model: if the water cut exceeds the given limit, the worst-offending connection of the producing well is shut.

Runs have been made with a maximum allowable water cut of 0.50, 0.60, 0.70, 0.75, 0.80, 0.85, 0.90 and 0.95. They show the following pattern: for maximum water cuts of 0.85 or less, the well is completely shut before the injector bottomhole pressure reaches 5200 psi, i.e. before the injection can be triggered. Therefore, for maximum water cuts of 0.85 or less, there is only a brief natural depletion period before the well is shut. We will therefore only consider maximum water cuts of 0.90 and 0.95. For these water cuts, the project finishes based on the economics: when the undiscounted cumulative cash flow is maximum, the wells are abandoned and the project stops.

To compare these 2 cases, we used the screening criteria defined in CHAPTER V. They are shown in Table 29. From this table, we can see that the only criterion for which the higher water cut is superior is the CO_2 imported. This is expected since allowing for a higher water cut means that more water is produced, which means there is more space available for the CO_2. On all other criteria, the lower water cut is superior, and it is even superior to the base case for some criteria.

Table 29: Values of the screening criteria for the considered maximum water cuts

Screening Criteria	Reference	WC 0.90	WC 0.95	Unit
Oil production plateau duration	4.6	5.2	4.6	years
Total oil production	231,236	222,022	206,313	STB
CO_2 imported	718,430	865,480	953,865	Mscf
Net Present Value @ 10%	858	700	423	MM$
Internal Rate of Return	44.1	44.9	33.9	%
Project Duration	20	13.9	12.6	years

The behavior of the cumulative cash flow for both maximum water cut cases is shown on Figure 50. The bump around 30 months corresponds to the injection is start: when the CO_2 injection starts, the operational expenditures increase quickly because of the high quantities of CO_2 that need to be imported, so the cash flow becomes negative (which corresponds to the decrease of the cumulative cash flow), until enough CO_2 is injected for its effect to be clearly felt at the producer. Then the water production starts decreasing thanks to the injection, and the need for imported CO_2 decreases as more gas is produced, and the cash flow becomes positive again.

The production then slowly declines until the operating costs become larger than the revenue. The well is then abandoned, which corresponds to the ultimate decrease.

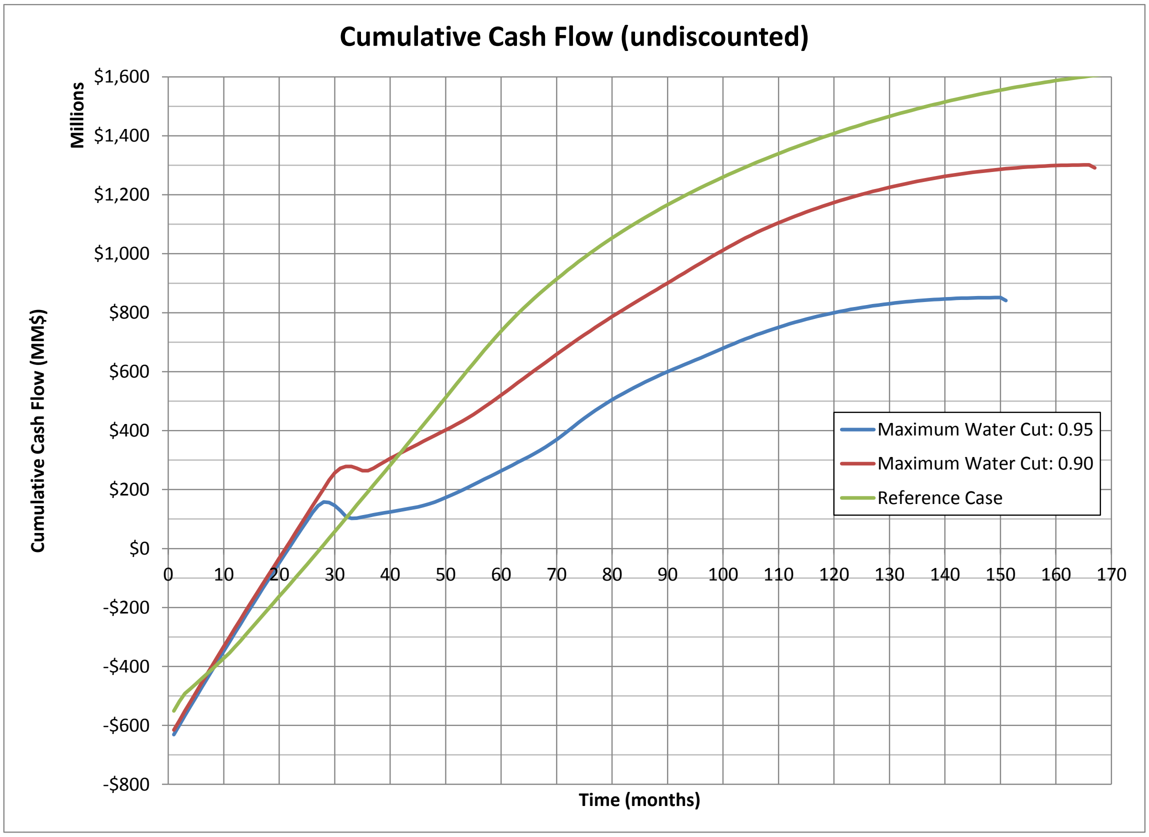

Figure 50: Cumulative cash flows for the Reference Case, and the CO_2-EOR cases with aquifer and different water cuts

The influence of the maximum water cut is therefore critical: allowing for a too low water cut does not enable for enough production, while allowing for too high water cuts means losing production and degrading the economics of the project. Therefore, should a CO_2-EOR project be implemented on a reservoir that has a significant aquifer drive, particular attention should be given to the optimization of the water cut cap.

The influence of the maximum water cut with a different injection schedule is studied in VI.5.1.

VI.4. Influence of the Wells Completion

VI.4.1. Producer Completion

It has been known for long that to avoid water coning and excessive water production that would kill the well, it is best to complete the production wells in the top part of a reservoir (Economides et al. 1994; Smith and Pirson 1963). In a way, this has been studied in paragraph VI.3 since the worst-offending connections of the producer were shut when the water cut was too high. However, it is interesting to investigate the behavior of the field when the producer is only completed in the top part of the reservoir. Two configurations have been tested: producer completed in the 10 layers of the reservoir, and producer completed only in the 5 top layers.

a. Natural Depletion

Figure 51 shows the advantages of completing the producer at the top of the reservoir in the case of a natural depletion scheme: the water production is decreased while the oil production plateau lasts longer. The recovery and the economics are better, because water coning is delayed.

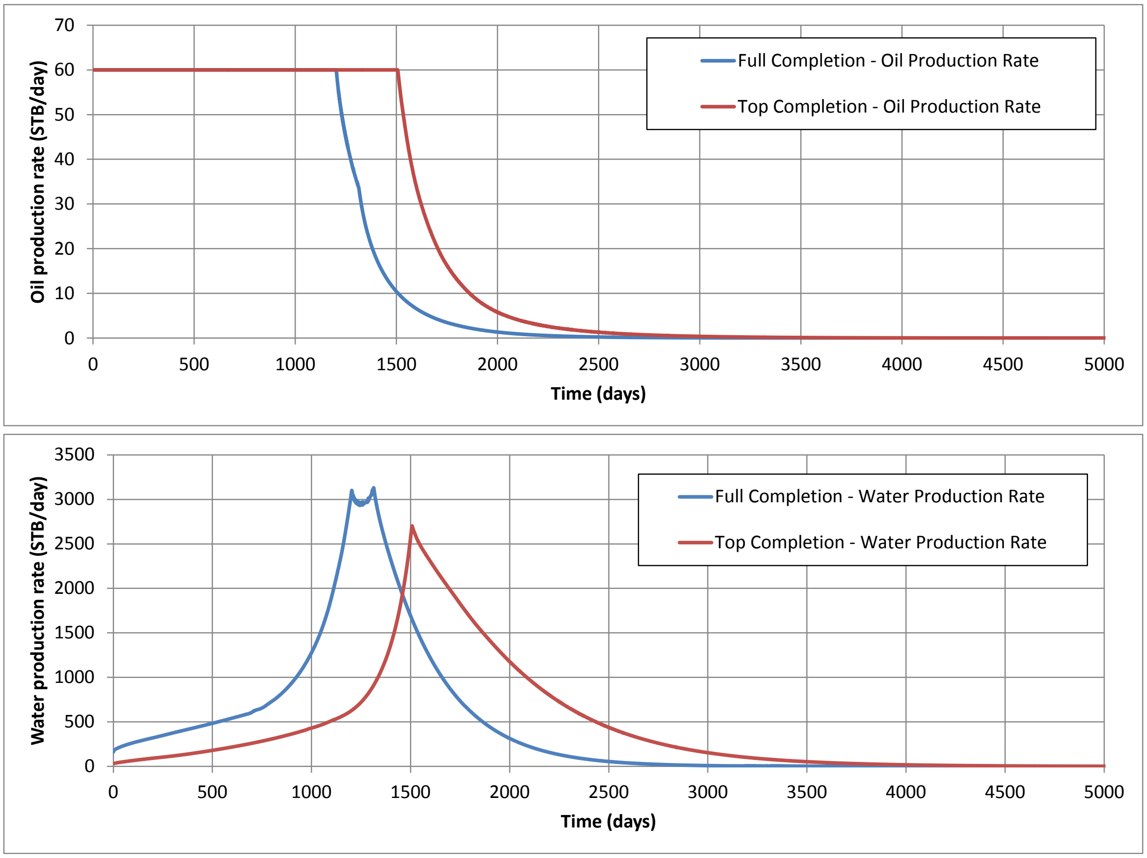

Figure 51: Oil and water production rates for top and full completion in a natural depletion case

b. CO_2-EOR Development Plan

It is interesting to assess the degree to which producer completion will affect a project that has a CO_2-EOR development plan, since coning is primarily prevented using the pressure maintenance from the injected gas in that case. As it can be seen on Figure 52, completing the producer only at the top enables to have a more stable oil production rate and a longer oil production plateau, which is already a positive consequence.

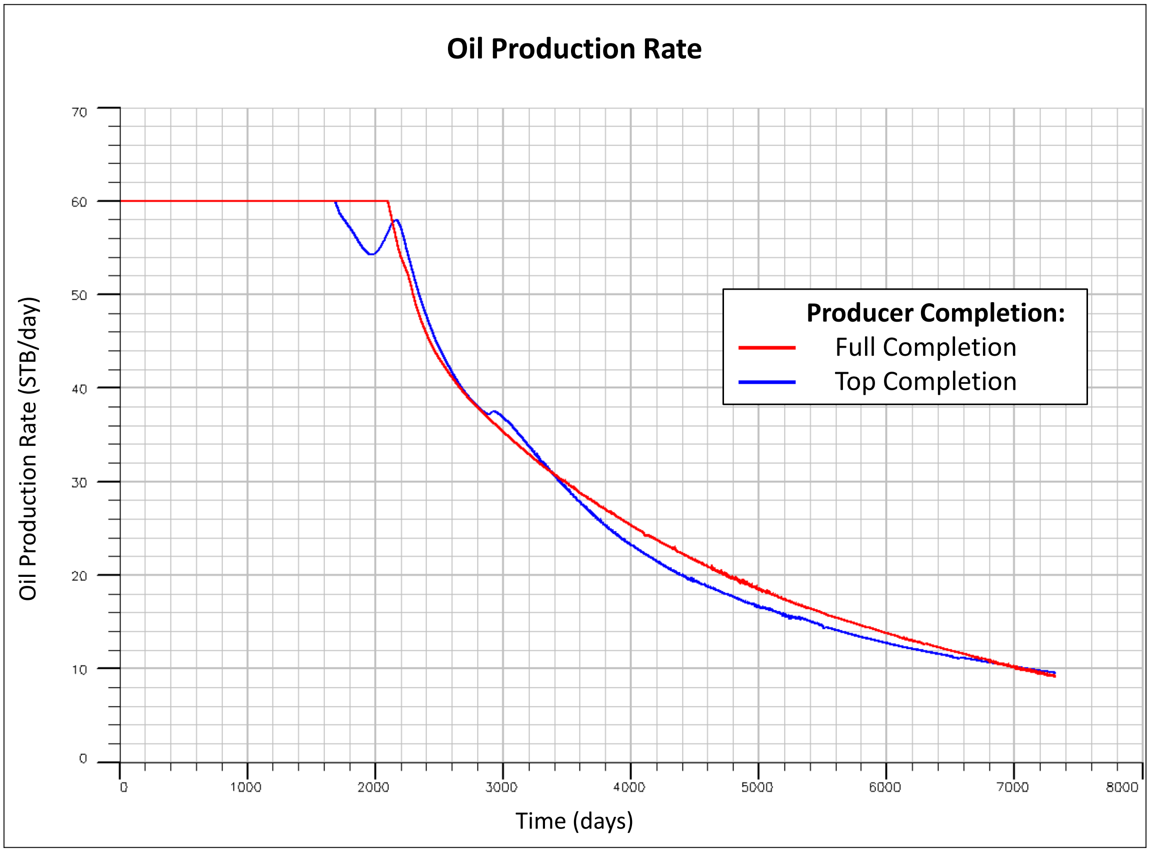

Figure 52: Oil production rate in a CO_2-EOR injection scheme with full and top producer completion

The values of the screening criteria are presented in Table 30. It shows the very interesting behavior: the only difference between the Reference Case and the "Full Completion" case is the added aquifer. Adding it reduces the interest of the project, apart from the increased CO_2 storage capacity. However, it is possible to reach measures equivalent to those of the reference case simply by completing the producer on the upper half of the reservoir.

Table 30: Values of the screening criteria for producer top and full completion

Screening Criteria	Reference	Full completion	Top completion	Unit
Oil production plateau duration	4.6	4.6	5.7	years
Total oil production	231,236	206,313	220,385	STB
CO_2 imported	718,430	953,865	747,482	Mscf
Net Present Value @ 10%	858	423	853	MM$
Internal Rate of Return	44.1	33.9	55.0	%
Project Duration	20	12.6	14.1	years

The study of the cumulative cash flow (Figure 53) explains why the economic measures are better for the cases with an aquifer: the revenues are generated earlier, and earliest in the case of a Top Completion.

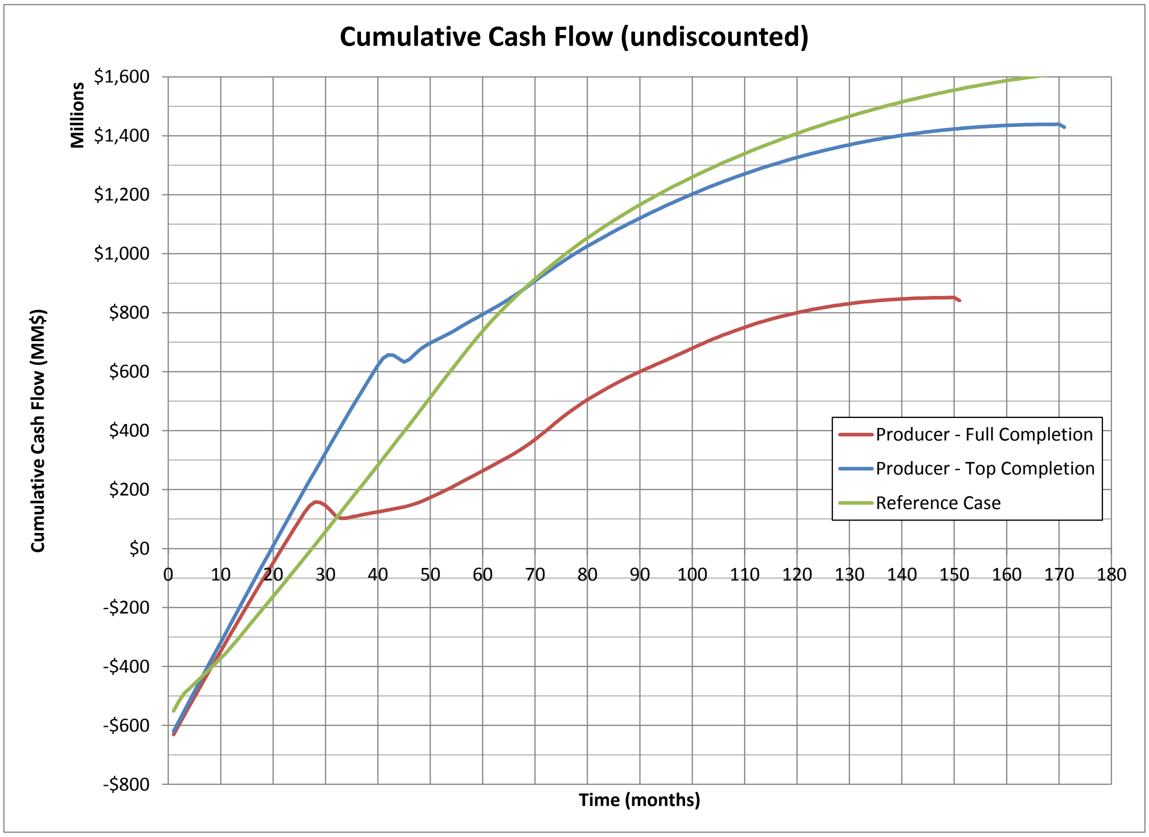

Figure 53: Cumulative cash flows for the Reference Case, and the CO_2-EOR cases with aquifer and different producer completions. The end of the reference case is voluntarily left out of range

It is demonstrated that even though CO_2 injection will act as a means to avoid coning, the advantage of completing the producer well in the top part of the reservoir has a very beneficial effect on the project.

VI.4.2. Injector Completion

The influence of the injector completion is harder to evaluate *a priori*: there is no obvious option that would yield better results. The first approach is to look at the oil recovery presented in Figure 54. It looks like the bottom completion does not hurt much the recovery, while the top completion is reducing it more. This conclusion is specific to the type of oil, and specifically to the density difference between CO_2 and the oil. For an oil lighter than the CO2, it should be the opposite.

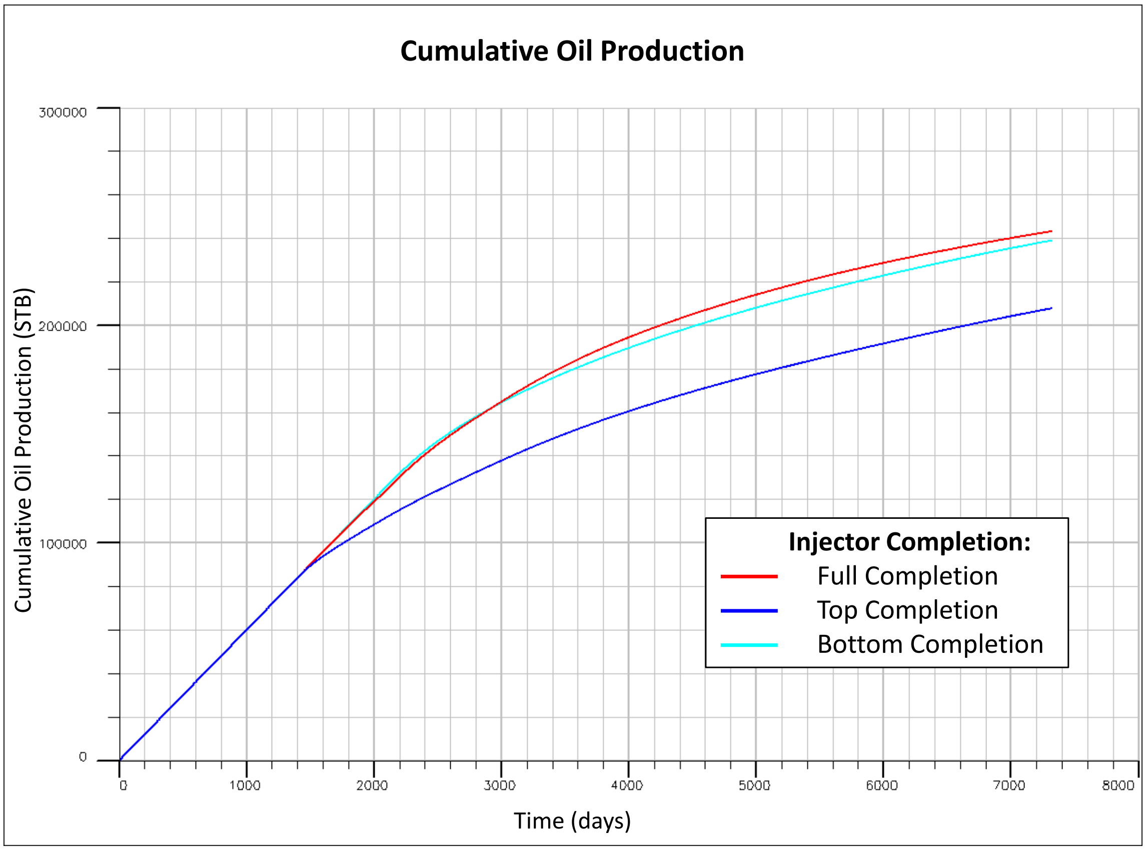

Figure 54: Cumulative oil production for different injector completions

This conclusion, however, does not take into account the economics of the project. On the previous figure, production occurs until the end of the 20 years, while in reality they would be stopped earlier if the cash flow became negative. Moreover, the operating costs are different as well: for instance, the case with the Bottom Completion requires more CO_2 imported and produces more water (Figure 55).

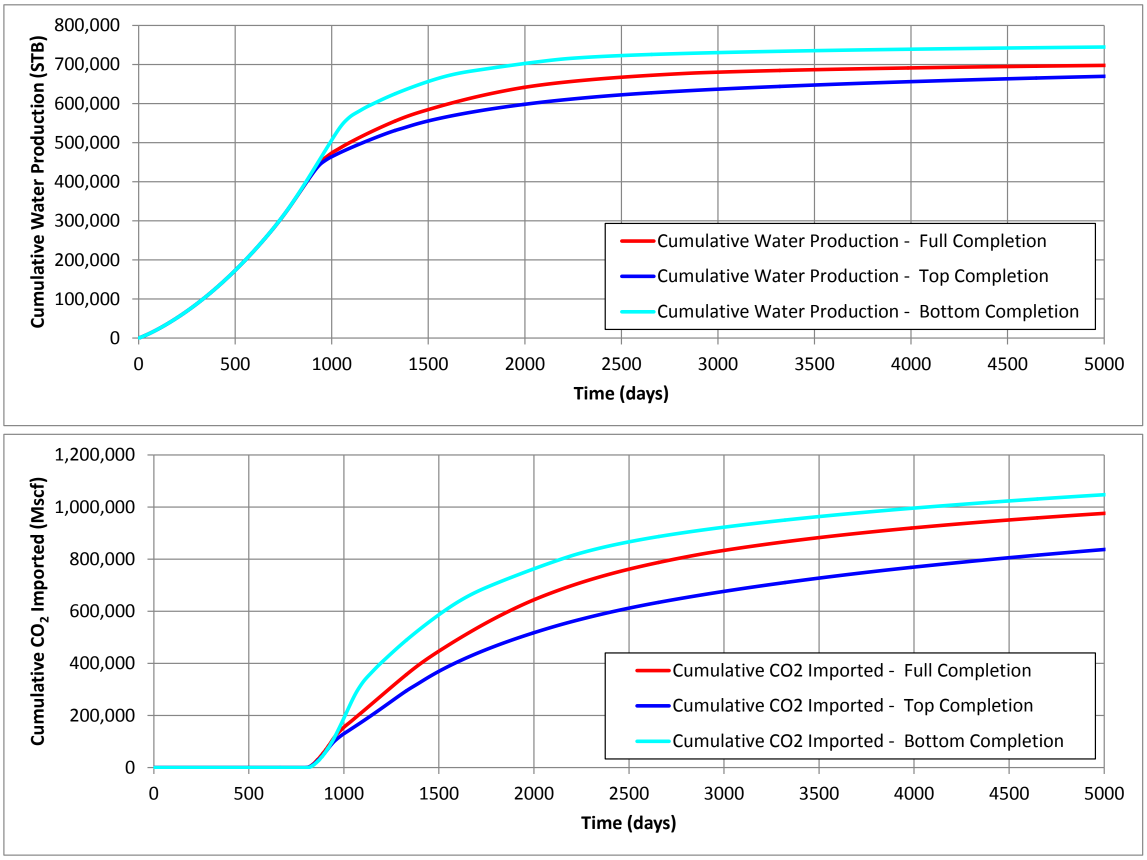

Figure 55: Cumulative water production and CO_2 imported for the 3 cases of injector completion

These results show that it is necessary to perform a detailed economic analysis, in order to assess further which solution is better, and when production should be stopped. The cumulative cash flow for each case is plotted on Figure 56. It shows that due to the higher costs that it generates, the Bottom Completion case has the worst cash flow profile, and is the first one to stop. Considering only the production that occurs before their economic end points, the 3 projects must be re-ranked.

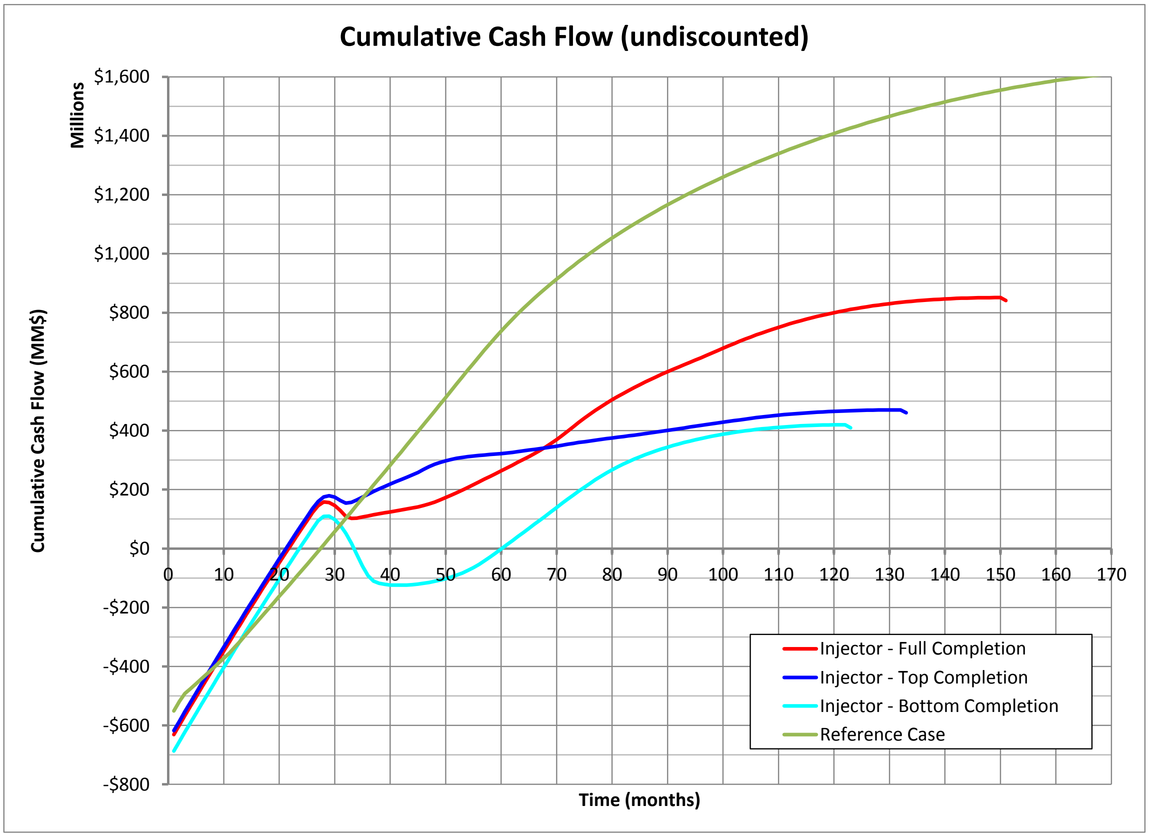

Figure 56: Cumulative cash flow for the 3 cases of injector completion

The values of the screening criteria for the 3 injector completion cases are given in Table 31. It appears that contrary to what appeared at first sight looking only at the oil recovery, the "Bottom Completion" case is not the best ranked, based on economic criteria. However, it has a higher oil recovery and storage potential than the "Top Completion" case. The "Full Completion" case, though is clearly the best.

Table 31: Values of the screening criteria for the 3 cases of injector completion

Screening Criteria	Reference	Full comp.	Top comp.	Bottom comp.	Unit
Oil production plateau	4.6	4.6	3.8	5.8	years
Total oil production	231,236	206,313	160,828	183,296	STB
CO_2 imported	718,430	953,865	770,915	978,038	Mscf
NPV 10	858	423	264	147	MM$
Internal Rate of Return	44.1	33.9	33.7	19.2	%
Project Duration	20	12.6	11.0	10.2	years

It is therefore shown here that using only production and injection totals in evaluation different injector completion scenarios. An economic analysis must be performed to draw accurate conclusions. In addition, it seems that a partial completion of the injector is not preferable to a full completion. It is therefore recommended complete the injector on the full thickness of the reservoir.

VI.5. Influence of the Injection Starting Date

Some cases, especially those run with different water cut limits, did not reach the injection trigger and therefore cannot be considered as they are for CO_2-EOR. One solution to this problem is to start the injection directly at the beginning of the project, with an injection pressure target equal to the initial reservoir pressure. In addition, this solution would increase the storage capacity of the reservoir. This is the strategy recommended by Bachu et al. (2004) for reservoirs with a strong water drive.

Depending on the producer completion and the water cut, results are different and will be discussed in the 2 following paragraphs.

VI.5.1. Full Producer Completion

Runs have been carried out with a full producer completion and a maximum water cut of 0.70, 0.75, 0.80, 0.85, 0.90 and 0.95. The workover procedure when the water cut is beyond the limit is to shut the worst-offending connection.

The first thing to notice is that the water cut for the well production reaches a maximum value of 0.82 for the 3 last cases (water cut limit = 0.85, 0.90 and 0.95) and never reaches the point where the producing rate has to be limited because of an excessive water cut. There is therefore no difference in the simulation between them.

The values of the screening criteria are presented in Table 32. They show a very clear trend: when the water cut limit decreases, the project economics get better and the recovery increases, while the CO_2 storage potential decreases. The cumulative cash flow profile is shown on Figure 57 and shows the very same trend.

These figures need to be compared with the ones obtained in VI.3, recalled in Table 33. For the same water cut limits (0.90 and 0.95), the metrics obtained with injection from the start are less favorable. However, the main goal of starting injection at the beginning of the project is to be able to use a lower water cut limit. Therefore, the metrics that should be compared are the ones for the following cases:

- Injection from the start, Water Cut limit = 0.70

- Injection from BHP injector = 5200 psi, Water Cut limit = 0.90

Comparing those 2 cases does not show a clear advantage for one or the other, all the values being in the same range (plus or minus 5%), except for the oil production plateau duration (18% longer for the injection at 5200 psi) and the total project duration (27% longer for the injection from the start).

We can therefore conclude that the injection starting date should be chosen along with a given water cut limit. There is not one combination that is better than the others. However, it is important to notice that earlier injection starting dates allow for lower water cuts. This means that choosing a later injection starting date will imply producing more water overall, even though the economics are similar. Therefore, choosing an early injection starting date should be a better choice for most projects.

Table 32: Values of the screening criteria for the different water cut limits, with injection starting from the beginning of the project

Screening Criteria	Reference Case	WC 0.70	WC 0.75	WC 0.80	WC 0.85 WC 0.90 WC 0.95	Unit
Oil plateau	4.6	4.4	4.2	4.2	4.6	years
Oil production	231,236	228,476	218,447	213,904	200,017	STB
CO_2 imported	718,430	855,335	1,005,030	1,020,903	1,086,947	Mscf
PV10	858	776	525	414	158	MM$
IRR	44.1	40.5	28.6	23.9	15.5	%
Project Duration	20	17.6	15.3	14.8	13.8	years

Table 33: Values of the screening criteria for the different water cut limits, with injection starting when the injector BHP reaches 5200 psi (from VI.3)

Screening Criteria	Reference Case	WC 0.90	WC 0.95	Unit
Oil Plateau	4.6	5.2	4.6	years
Total oil production	231,236	222,022	206,313	STB
CO_2 imported	718,430	865,480	953,865	Mscf
PV10	858	700	423	MM$
IRR	44.1	44.9	33.9	%
Project Duration	20	13.9	12.6	years

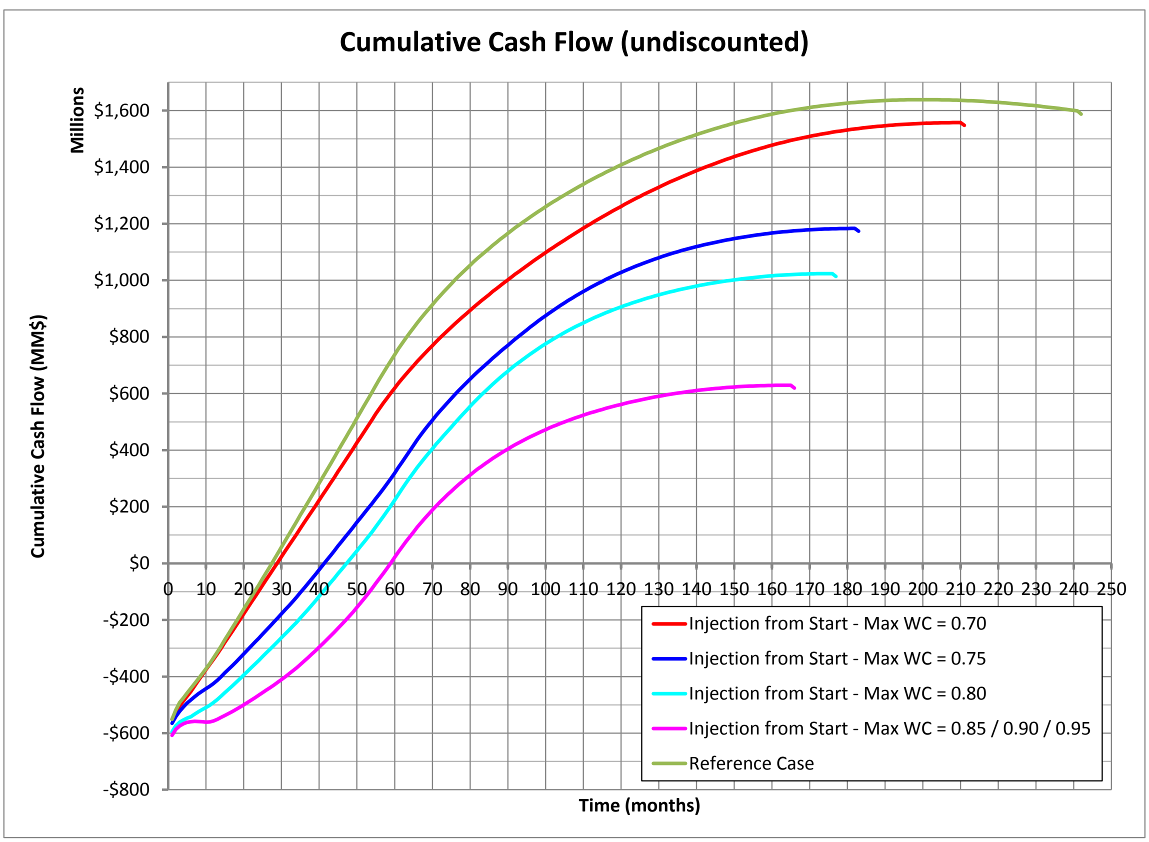

Figure 57: Cumulative cash flow profiles for the different water cut limits, with injection starting from the beginning of the project

VI.5.2.   Top Producer Completion

As we saw in VI.4.1, it is better to complete the producer only in the upper part of the reservoir. If this is the case, without imposing any constraints on the maximum water cut, the water cut never becomes larger than 0.6 (see Figure 58). This is due to the fact that after a phase during which water is drawn to the well due to the pressure drawdown, the injected gas breaks through and maintains the pressure in the producer zone as well. As a consequence, there is no need to impose a cap to the water cut.

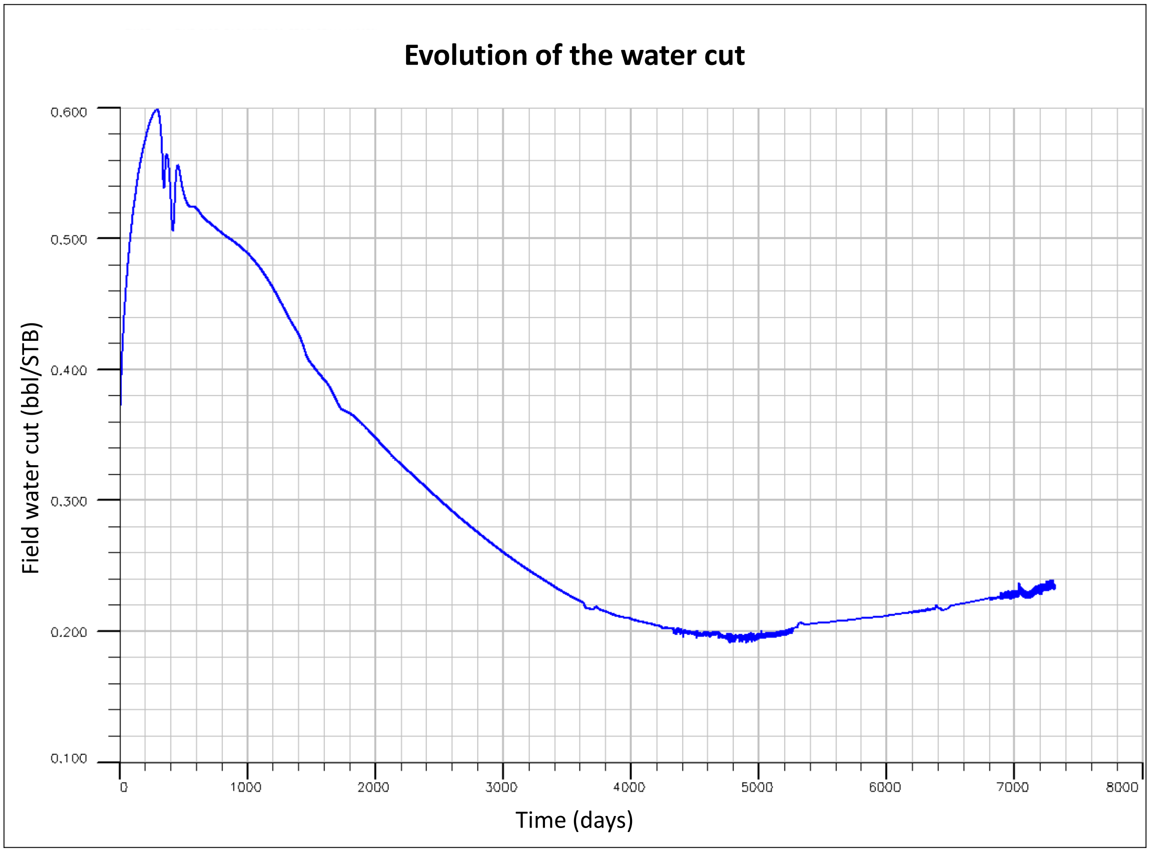

Figure 58: Evolution of the water cut over time for an injection from the start and a producer completed in the upper part of the reservoir

It is interesting to compare this case to the Reference Case and the 2 best cases described in the previous paragraph (VI.5.1):

- Run 1: injection starts when the BHP of the injector reaches 5200 psi, maximum water cut of 0.90
- Run 2: injection starts at the beginning of the project, maximum water cut of 0.70
- Run 3 (Top Comp.): same as Run 2, with the producer completed only in the upper 5 layers of the reservoir

The important metrics are given in Table 34. What it shows is that Run 3 is a significant improvement over Run 2, except for the storage potential. This confirms that completing the producer only in the top part of the reservoir is a good strategy. The comparison between Run3 and Run 1 is harder to make, and no case really stands out as better than the other.

Table 34: Values of the screening criteria for the 3 last runs

Screening Criteria	Ref. Case	Run 1	Run 2	Run 3	Unit
Oil prod. plateau	4.6	5.2	4.4	4.4	years
Oil production	231,236	222,022	228,476	230,037	STB
CO_2 imported	718,430	865,480	855,335	850,579	Mscf
PV10	858	700	776	813	MM$
IRR	44.1	44.9	40.5	43.3	%
Project Duration	20	13.9	17.6	17.9	years

The injection start can therefore be chosen in a wide range, from the beginning of the project. However, one has to keep in mind that the maximum allowable water cut should be adapted to the injection start; if it is not the case, oil recovery, storage potential and economic performance will be impacted in a significant way.

VI.6. Conclusions on the Influence of the Aquifer

The most visible impact is the producer completion: to avoid water coning, and even if the well has economic constraints that will shut the worst-offending connections if the water cut is too large, the producing well should be completed in the upper part of the reservoir.

The injector should be completed in the whole reservoir thickness; even though, looking at recovery values, bottom-only completion does not seem to harm much the strategy, economics show that it has a large impact.

The maximum water cut should be set as low as possible to maximize the economic interest of a project. However, minimizing the water cut will decrease the CO_2 storage potential.

There is no global recommendation for the injection starting date, as long as the maximum water cut is adapted to it. If it is not the case, significant losses in recovery, CO_2 storage potential and economic efficiency will happen.

CHAPTER VII

SENSITIVITY OF THE ECONOMICS TO KEY PARAMETERS

The aim of this chapter is to evaluate the sensitivity of the model to key economic parameters:

- CO_2 market price
- Oil price
- Distance from the CO_2 source to the field
- CO_2 source type
- Pipeline cost scenario

No sensitivity is run on the gas price because in these projects, the produced gas that has a high CO_2 content is recycled and not sold.

VII.1. Sensitivity Runs Results

The runs have been carried out by changing one parameter at a time on the Reference Case and on the optimized Alternative Case. The criteria study are the main economic measures: Net Present Value discounted @ 10% (PV10), Internal Rate of Return (IRR), and payout period.

VII.1.1. CO_2 Market Price

The models run consider no CO_2 market price. However, if a CO_2 tax were implemented, the incentive to develop CO_2-EOR projects could be even larger. A CO_2 tax would generate additional revenue for the quantities of CO_2 stored. The values tested are based on the value of the CO_2 futures on the European carbon market. The current value lies around €5 per metric ton of CO_2 (about 6.5 US$). Values of the 2020 futures reached up to €28 per metric ton of CO_2 (about 35 US$). Therefore the values tested for the CO_2 market price are 0 (reference cases), 7, 15, 25 and 35 US$ per metric ton of CO_2.

The results are shown in Table 35 and Table 36.

Table 35: Sensitivity to the CO_2 market price (values)

Market Price of CO_2	Reference Case			Alternative Case		
	PV10 (MM$)	IRR (%)	Payout (months)	PV10 (MM$)	IRR (%)	Payout (months)
$0 / mton	**858**	**44.1%**	**27**	**815**	**51.2%**	**22**
$7 / mton	903	45.9%	26	867	52.9%	21
$15 / mton	971	48.6%	25	926	54.9%	21
$25 / mton	1,046	51.6%	23	1,000	57.3%	20
$35 / mton	1,121	54.6%	22	1,074	59.6%	19

Table 36: Sensitivity to the CO_2 market price (relative to the reference cases)

Market Price of CO_2	Reference Case			Alternative Case		
	PV10 (MM$)	**IRR (%)**	**Payout (months)**	**PV10 (MM$)**	**IRR (%)**	**Payout (months)**
$0 / mton	-	-	-	-	-	-
$7 / mton	+ 5.3%	+ 4.0%	- 3.7%	+ 6.4%	+ 3.4%	- 4.5%
$15 / mton	+ 13.1%	+ 10.1%	- 7.4%	+ 13.6%	+ 7.3%	- 4.5%
$25 / mton	+ 21.9%	+ 16.8%	- 14.8%	+ 22.7%	+ 12.0%	- 9.1%
$35 / mton	+ 30.7%	+ 23.6%	- 18.5%	+ 31.8%	+ 16.6%	- 13.6%

VII.1.2. Oil Price

The oil price assumed in the reference projects is $85 per stock tank barrel. However, the oil prices can be subject to important changes, as shown on Figure 59.

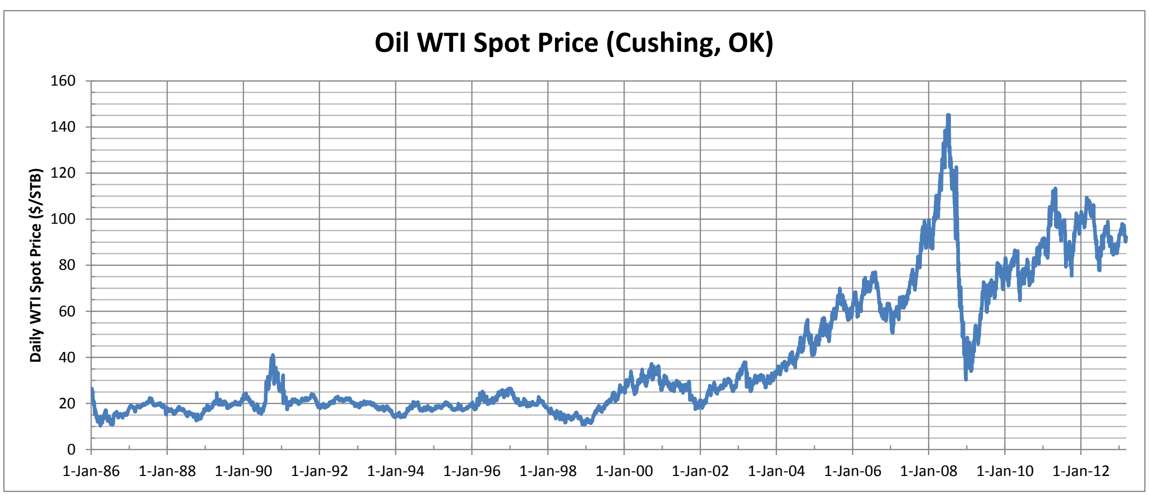

Figure 59: Spot price of the oil on the WTI market from 1986 to 2013 (EIA)

Even though extreme events such as the peak and trough that happened in 2008 are not likely to happen and do not represent stable tendencies in the long term, predictions as low as \$50 per stock tank barrel and as high as \$120 per stock tank barrel are possible (EIA 2011; IEA 2011a, 2011b). Runs have therefore been carried out with oil prices of \$85/STB (reference), \$50/STB, \$70/STB, \$100/STB, and \$120/STB. The minimum oil price to get a positive PV10 is 56.4 \$/STB for the Reference Case, 56.6% \$/STB for the Alternative Case. The results are presented in Table 37 and Table 38.

Table 37: Sensitivity to the oil price (values)

Oil Price	Reference Case			Alternative Case		
	PV10 (MM\$)	IRR (%)	Payout (months)	PV10 (MM\$)	IRR (%)	Payout (months)
\$50 / STB	-193	-	-	-188	-	-
\$70 / STB	407	28.7%	37	385	33.0%	30
\$85 / STB	**858**	**44.1%**	**27**	**815**	**51.2%**	**22**
\$100 / STB	1309	58.5%	21	1245	67.6%	17
\$120 / STB	1910	77.1%	16	1818	88.4%	14

Table 38: Sensitivity to the oil price (relative to the reference cases)

Oil Price	Reference Case			Alternative Case		
	PV10 (MM\$)	IRR (%)	Payout (months)	PV10 (MM\$)	IRR (%)	Payout (months)
\$50 / STB	- 122.5%	Undef.	Undef.	- 123.1%	Undef.	Undef.
\$70 / STB	- 52.5%	- 35.0%	+ 37.0%	- 52.7%	- 35.5%	+ 36.4%
\$85 / STB	-	-	-	-	-	-
\$100 / STB	+ 52.5%	+ 32.6%	- 22.2%	+ 52.7%	+ 32.2%	- 22.7%
\$120 / STB	+ 122.5%	+ 74.6%	- 40.7%	+ 123.1%	+ 72.8%	- 36.4%

VII.1.3. CO_2 Source to Field Distance

The CO_2 source distance from the field is a key parameter of the project. Ideally, the new projects try as much as possible to have very close proximity to avoid transport costs. However, existing projects such as the one in the Weyburn field, in the Williston basin in Canada, are viable with long distance transport: in the case of Weyburn, the CO_2 is transported over 200 miles (IEA GHG 2009; US Department of Energy 2008).

Sensitivity runs have therefore been run with source-field distances of 60 miles (reference cases), 5 miles, 30 miles, 100 miles and 200 miles. The results are presented in Table 39 and Table 40. The maximum distance between the CO_2 source and the field that still has a positive PV10 is 720 miles for the Reference Case, and 838 miles for the Alternative Case. The modification of the source-field distance has the largest effect on the IRR, because it decreases the initial investment.

Table 39: Sensitivity to the source-field distance (values)

Source-Field Distance	**Reference Case**			**Alternative Case**		
	PV10 (MM$)	**IRR (%)**	**Payout (months)**	**PV10 (MM$)**	**IRR (%)**	**Payout (months)**
5 miles	911	48.6%	25	856	55.7%	20
30 miles	888	46.6%	26	839	53.7%	21
60 miles	**858**	**44.1%**	**27**	**815**	**51.2%**	**22**
100 miles	815	40.9%	29	781	47.7%	23
200 miles	697	33.6%	33	689	39.9%	27

Table 40: Sensitivity to the source-field distance (relative to the reference cases)

Source-Field Distance	Reference Case			Alternative Case		
	PV10 (MM$)	IRR (%)	Payout (months)	PV10 (MM$)	IRR (%)	Payout (months)
5 miles	+ 6.1%	+ 10.1%	- 7.4%	+ 5.0%	+ 9.0%	- 9.1%
30 miles	+ 3.5%	+ 5.6%	- 3.7%	+ 2.9%	+ 5.0%	- 4.5%
60 miles	-	-	-	-	-	-
100 miles	- 5.1%	- 7.3%	7.4%	- 4.2%	- 6.7%	4.5%
200 miles	- 18.7%	- 23.8%	22.2%	- 15.5%	- 22.0%	22.7%

VII.1.4. CO_2 Source Type

Several technologies exist to capture CO_2 from the effluents of a power plant (IEA and Finkenrath 2011). As they have different costs (paragraph III.5.1), using different technologies changes the economics of a project. Sensitivity runs were carried out with all the technologies listed by the IEA. The results are shown in Table 41 and Table 42.

Table 41: Sensitivity to the CO_2 production technology (values)

CO_2 Production Technology		Reference Case			Alternative Case		
		PV10 MM$	IRR %	Payout months	PV10 MM$	IRR %	Payout months
1	**Coal - Pre-Comb. - IGCC**	948	47.7%	25	904	54.1%	21
2	**Coal - Oxy-Comb. - PC**	881	45.0%	26	837	51.9%	22
3	**Coal - Pre-Comb. - PC**	**858**	**44.1%**	**27**	**815**	**51.2%**	**22**
4	**Coal - Post-Comb. - PC**	836	43.3%	27	793	50.4%	22
5	**NG - Post-Comb. - NGCC**	670	36.8%	32	630	44.5%	24

Table 42: Sensitivity to the CO_2 production technology (relative to the reference cases)

CO_2 Production Technology		Reference Case			Alternative Case		
		PV10 MM$	IRR %	Payout months	PV10 MM$	IRR %	Payout months
1	Coal - Pre-Comb. - IGCC	+ 10.5%	+ 8.0%	- 7.4%	+ 10.9%	+ 5.9%	- 4.5%
2	Coal - Oxy-Comb. - PC	+ 2.6%	+ 2.0%	- 3.7%	+ 2.7%	+ 1.5%	0.0%
3	Coal - Pre-Comb. - PC	-	-	-	-	-	-
4	Coal - Post-Comb. - PC	- 2.6%	- 2.0%	0.0%	- 2.7%	- 1.5%	0.0%
5	NG - Post-Comb. - NGCC	- 21.9%	- 16.6%	+ 18.5%	- 22.7%	- 13.0%	+ 9.1%

VII.1.5. Pipeline Cost Scenario

As seen in part III.5.3, several models exist to evaluate the cost of the pipeline to transport CO_2. Three models have been developed: low estimate, mean estimate and high estimate. The influence of this parameter on the economics should be investigated. The results of the sensitivity runs are shown in Table 43 and Table 44.

Table 43: Sensitivity to the pipeline cost scenario (values)

Pipeline Cost Scenario	Reference Case			Alternative Case		
	PV10 (MM$)	IRR (%)	Payout (months)	PV10 (MM$)	IRR (%)	Payout (months)
Low	880	45.9%	26	833	53.1%	21
Mean	**858**	**44.1%**	**27**	**815**	**51.2%**	**22**
High	829	41.9%	28	793	48.9%	23

Table 44: Sensitivity to the pipeline cost scenario (relative to the reference cases)

Pipeline Cost Scenario	Reference Case			Alternative Case		
	PV10 (MM$)	IRR (%)	Payout (months)	PV10 (MM$)	IRR (%)	Payout (months)
Low	+ 2.6%	+ 4.0%	- 3.7%	+ 2.2%	+ 3.8%	- 4.5%
Mean	-	-	-	-	-	-
High	- 3.4%	- 5.0%	+ 3.7%	- 2.7%	- 4.4%	+ 4.5%

VII.2. Analysis of the Orders of Magnitude

Without surprise, since oil is the only source of revenue for these projects, the oil price is the parameter that has the largest impact on the projects' economics. The other parameters have a comparable impact. The influence of the different variables is presented on Figure 60, Figure 61, Figure 62 and Figure 63. The key to this figure is given in Table 45.

Table 45: Summary of possible variations of the key variables

	- -	-	0	+	++	+++	++++	Unit
Oil Price	50	70	85	100	120			$/STB
CO_2 Price			0	7	15	25	35	$/mton
Source-field distance	5	30	60	100	200			mi
Pipeline cost scenario		Low	Mean	High				-
CO_2 source[2]	1	2	3	4	5			-

[2] The numbers given here correspond to those described in Table 41. 1: Coal - Pre-Comb. – IGCC; 2: Coal - Oxy-Comb. – PC; 3: Coal - Pre-Comb. – PC; 4: Coal - Post-Comb. – PC, 5: NG - Post-Comb. - NGCC

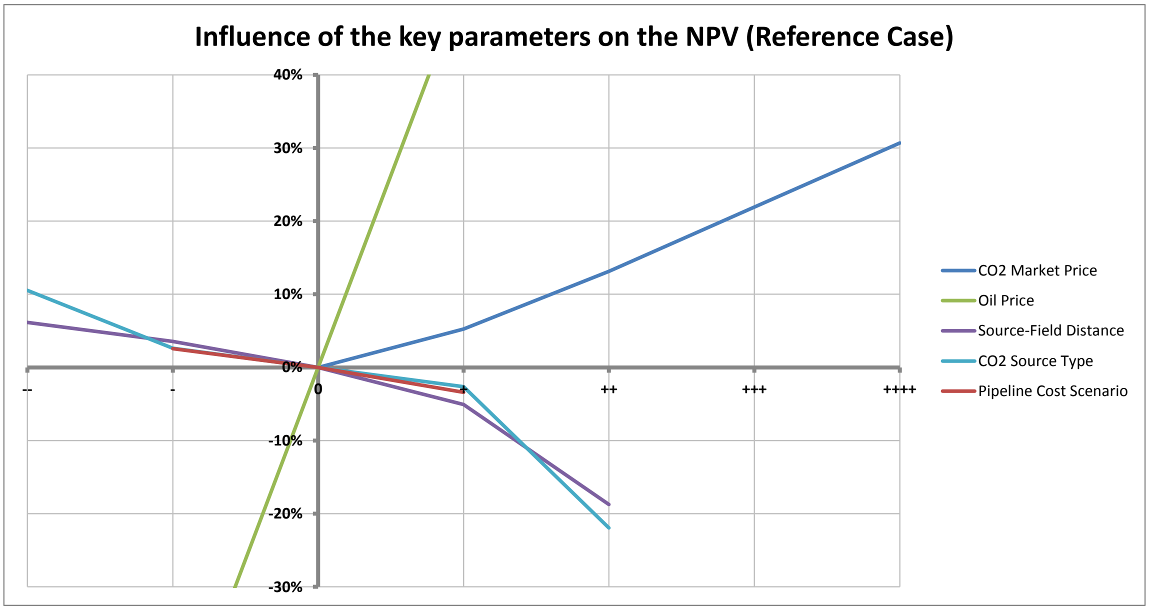

Figure 60: Influence of the key variables on the PV 10 for the Reference Case

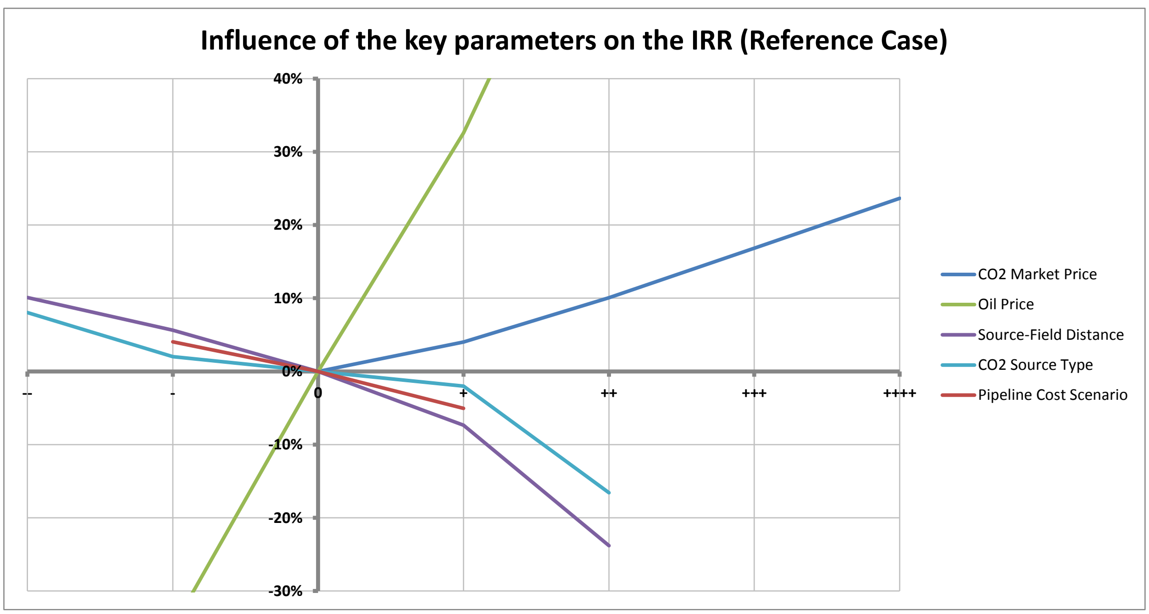

Figure 61: Influence of the key variables on the IRR for the Reference Case

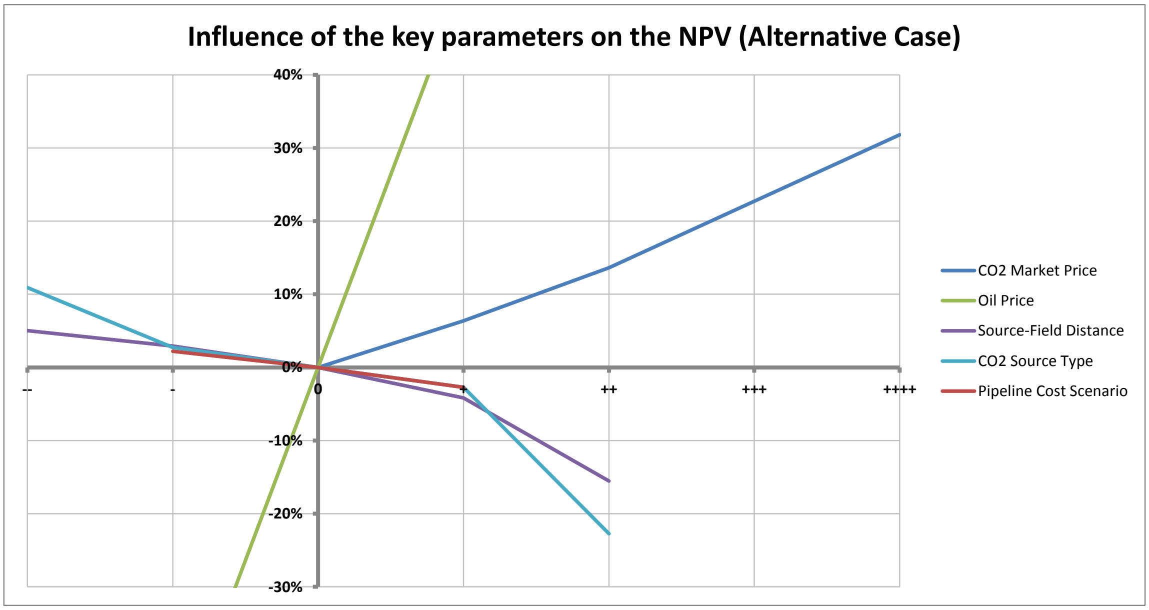

Figure 62: Influence of the key variables on the PV 10 for the Alternative Case

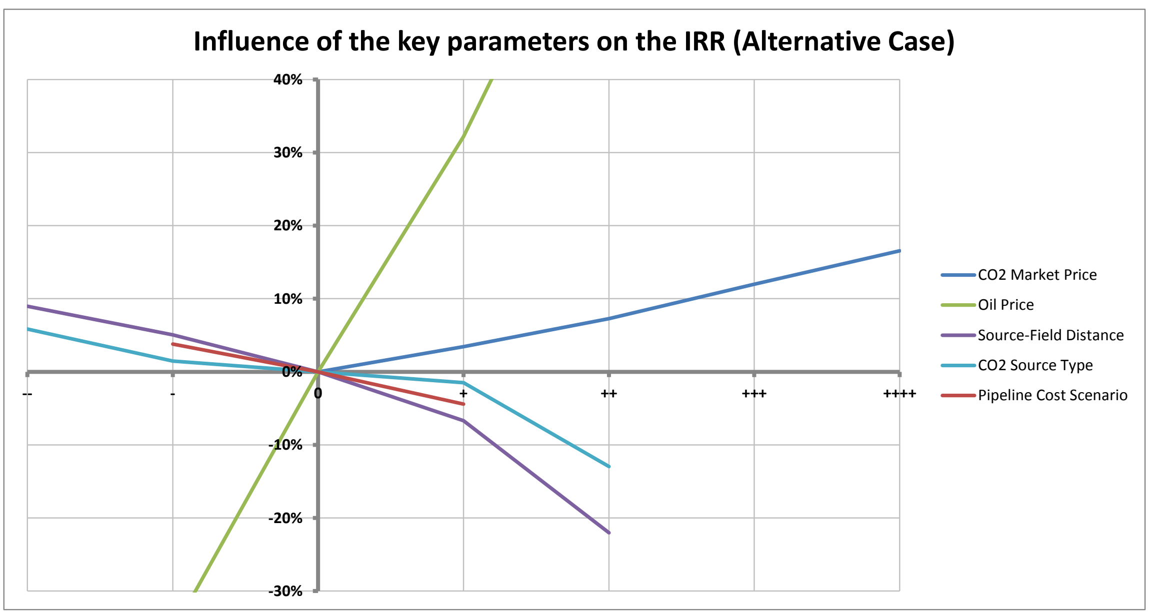

Figure 63: Influence of the key variables on the IRR for the Alternative Case

Some interesting patterns can be spotted on this figure. First, they show that the source-field distance has a stronger influence on the IRR than on the PV10. In the same way, the CO_2 source type has a larger influence on the PV10 than on the IRR.

What is interesting to assess as well is how the effects of some variables can be balanced by others. For instance, creating an integrated project where the source-field distance is 5 miles instead of 60 increases the PV10 of the project of 52 million US$. This impact is equivalent in order of magnitude to the introduction of a $7 / ton CO_2 emission tax, or the difference of PV10 between the lowest and highest pipeline scenarios.

Table 46 shows the orders of magnitude of the changes on the NPV, and shows how the key economic parameters are related.

Table 46: Comparison of the possible causes for a given PV10 change (Reference Case)

NPV Variation	Possible causes of the variation
NPV - 1,050 MM$	• Oil price reduced from $85/STB to $50/STB (-41.1%)
NPV - 450 MM$	• Oil price reduced from $85/STB to $70/STB (-17.6%)
NPV - 200 MM$	• CO_2 source changed from Coal pre-combustion to NG post-combustion
NPV - 150 MM$	• Source-field distance increased from 60 to 200 miles
NPV - 50 MM$	• Source-field distance increased from 60 to 100 miles
NPV - 25 MM$	• CO_2 source changed from pre-combustion to post-combustion • CO_2 pipeline cost scenario changed from mean to low
NPV + 25 MM$	• Source-field distance reduced from 60 to 30 miles • CO_2 source changed from pre-combustion to oxy-combustion • CO_2 pipeline cost scenario changed from mean to high
NPV + 50 MM$	• Source-field distance reduced from 60 to 5 miles • CO_2 emission tax of $7 / ton of CO_2 • CO_2 pipeline cost scenario changed from low to high
NPV + 100 MM$	• CO_2 source changed from pre-combustion PC to oxy-combustion IGCC • CO_2 emission tax of $15 / ton of CO_2
NPV + 200 MM$	• CO_2 emission tax of $25 / ton of CO_2
NPV + 250 MM$	• CO_2 emission tax of $35 / ton of CO_2
NPV + 450 MM$	• Oil price increased from $85/STB to $100/STB (+17.6%)
NPV + 1,050 MM$	• Oil price increased from $85/STB to $120/STB (+41.1%)

CHAPTER VIII

CONCLUSIONS AND RECOMMENDATIONS

VIII.1. Conclusions

An integrated model for CO_2-EOR projects was developed and tested. The metrics yielded by the model were compared to published figures and are consistent. The economic component model synthetizes the existing models and lets the user choose inputs. The main advantage of this coupled model is that it allows testing any kind of production and injection schedule, while accurately modeling the fluid flows.

Using the model developed, injection strategies were tested, and the influences of key parameters were assessed. The main conclusions are the following.

- A set of representative screening criteria provided by the model gives a good tool to evaluate different projects:
  - Oil production plateau duration
  - CO_2 import plateau duration (if applicable)
  - Total oil production
  - Total CO_2 imported
  - Internal Rate of Return
  - Net Present Values (discounted at 10%)
  - Payout period

- **Maximum production rates for oil and gas** impact the performance of the project and are the first parameters that should be chosen. A screening method to determine the optimal constraints was used and proved accurate.
- **Injection starting date** should be chosen before the oil production plateau terminates, if the reservoir is produced by natural depletion only. Within this range, it should be optimized based on the screening criteria and in accordance with the import CO_2 plateau rate.
- **Import CO_2 plateau rate** should be optimized simultaneously with the injection starting date.

Starting from a typical reference case, it was shown that adding constraints on the import CO_2 stream, such as imposing a production plateau, can be done at little cost to the performance of the project. A method to optimize the production and injection parameters is provided. This method can be applied to any reservoir, using the same model with different inputs.

The influence of aquifer support on CO_2-EOR strategies was assessed. It was shown that a good design of the strategy is crucial to ensure that the project has the best efficiency. The producing well must be completed at the top of the reservoir, and shutting in worst-offending well connections as the water cut increases is not an efficient strategy. The injectors should be completed over the entire reservoir thickness. The maximum water cut should be set as low as possible, but it must be chosen in accordance with the injection start date. If not, the project will be significantly impacted. An early injection start is recommended, even though it is not mandatory.

Finally, the sensitivity of some key parameters on a project's economics was assessed. The most significant parameter by far is the oil price. The 4 other parameters evaluated (CO_2 market price, source-field distance, CO_2 source type and pipeline cost scenario) have roughly the same influence: this means that an increase of one could be compensated by a decrease of another. For instance, the increase of the source-field distance from 5 to 60 miles could be offset by increasing the CO_2 price by $7/mton.

VIII.2. Recommendations

The main recommendation is to continue evaluating new CO_2-EOR strategies using the model presented in this thesis. For instance, alternating periods of natural depletion with periods of injection could be an interesting strategy. Water alternating gas (WAG) could also be a scheme to investigate.

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APPENDIX 1

ECLIPSE *.DATA FILE FOR THE REFERENCE CASE

```
--
=======================================================================
--
--    THESIS:
--    PERFORMANCE OF EOR-CO2 MISCIBLE PROCESS USING A CONCEPTUAL MODEL
--    December 2012
--    Martin Saint-Felix
--    Base Case Aquifer Scenario *.DATA file
--
--
=======================================================================
--
--Begin Amarile Project Manager Criteria. Please do not edit.
--Max Gas Rate=450
--Max Oil Rate=60
--Parent=BC2
--End Amarile Project Manager Criteria
MEMORY
100 10 /

--
=======================================================================
RUNSPEC This section is mandatory and it is used to set up the
--      especification for the simulation run.
--
=======================================================================

FIELD

DIMENS
--Nx   Ny   Nz
  31   16   10 /

WELLDIMS
  2   10   2   2 /

COMPS
--Use 5 components
```

```
  5 /

START
  1 JAN 2012 /

TABDIMS
--Determines the # of pressure and saturation tables and the maximum #
of rows
  1   1   40   40 /

WATER

AIM
--AIM solution method, avoids time step restrictions

EOS
--Peng-Robinson equation of state to be used
  PR /


NSTACK
  200 /

MULTSAVE
--Overwrite the save at each state
  0 /

--formatting of the output files
UNIFOUT
UNIFOUTS


--======================================================================
GRID    This section is mandatory and it is used to input the grid
--      or cells to be ussed into teh simulation model.
--======================================================================
-- MODEL 25*25*36 EACH BLOK 32FT (PERMEABILITY AND POROSITY
DISTRIBUTION)

EQUALS

--VALUE  X    X    Y    Y    Z    Z
  DX     32   1    31   1    16   1    10  /
  DY     32   1    31   1    16   1    10  /
  DZ     10   1    31   1    16   1    10  /
/
```

```
TOPS
  496*11453
/

INCLUDE
  ACTNUM.INC /

--Define Local Grid

PORO
  4960*0.2
/

PERMX
  496*180
  496*30
  496*500
  496*250
  496*10
  496*275
  496*150
  496*70
  496*310
  496*30
/

COPY
  PERMX   PERMY /
  PERMX   PERMZ /
/

MULTIPLY
  PERMZ   0.1 /
/


INCLUDE
  MULTIPLY.INC /


--=================================================================
PROPS   This section is mandatory and it is used to incorporate the
--      fluid and reservoir properties
--=================================================================
```

```
--You will use an entirely different fluid file in this include
statement, this is not
-- given here

INCLUDE
  PVT_1.PVO /


SWFN
--Water saturation functions (you may change these and use Kr as a
function of IFT - See Miscible key
--word and Eclipse manual
--SWAT   KRW     PCOW
  0.2    0.000   32
  0.24   0.003   21
  0.28   0.010   15.5
  0.32   0.023   12
  0.36   0.040   9.2
  0.4    0.063   7
  0.44   0.090   5.3
  0.48   0.123   4.2
  0.52   0.160   3.4
  0.56   0.203   2.7
  0.6    0.250   2.1
  0.64   0.303   1.7
  0.68   0.360   1.3
  0.72   0.423   1
  0.76   0.490   0.7
  0.8    0.563   0.5
  0.84   0.640   0.4
  0.88   0.723   0.3
  0.92   0.810   0.2
  0.96   0.903   0.1
  1      1.000   0
/

SGFN
--Gas saturation functions(you may change these)
--SGAS   KRG     PCOG
  0      0       0
  0.05   0.000   0.1
  0.1    0.004   0.2
  0.15   0.015   0.3
  0.2    0.033   0.4
  0.25   0.059   0.5
  0.3    0.093   0.6
```

```
  0.35   0.133   0.7
  0.4   0.181   0.8
  0.45   0.237   0.9
  0.5   0.300   1
  0.55   0.370   1.1
  0.6   0.448   1.2
  0.65   0.533   1.3
  0.7   0.626   1.4
  0.75   0.726   1.5
  0.8   0.834   1.6
/

SOF3
--Oil saturation functions(you may change these)
--SOIL   KRO      PC
  0   0      0.000
  0.3   0.000   0.000
  0.33   0.005   0.005
  0.36   0.018   0.018
  0.39   0.038   0.038
  0.42   0.064   0.064
  0.45   0.096   0.096
  0.48   0.133   0.133
  0.51   0.175   0.175
  0.54   0.223   0.223
  0.57   0.275   0.275
  0.6   0.333   0.333
  0.63   0.395   0.395
  0.66   0.462   0.462
  0.69   0.533   0.533
  0.72   0.609   0.609
  0.75   0.690   0.690
  0.78   0.775   0.775
  0.8    0.834   0.834
/

ROCKOPTS
/

ROCK
--Reference Pressure and Rock compressibility
  6017   4e-6 /

PVTW
--Pref   Bw    Cw          Uw
  6017   1.0   0.000003   0.31   0.0 /
```

```
DENSITY
--Surface density of water
  1*   63.0   1* /


--
======================================================================
SOLUTION This section is mandatory
--
======================================================================
--Defines the initial solution into the reservoir, adjust according to
selected pressure


EQUIL
--FT      PRES   WOC    Pc    GOC   (you may change these)
  11453   6017   11553 /

OUTSOL
--Solution output for GRAF (you may change these and add more
performance indicators)
  PRESSURE  SOIL  SWAT  SGAS  XMF  YMF  ZMF /

RPTSOL
--Output to the initial solution to the print files (you may change
these)
  PRESSURE  SOIL  SWAT  SGAS /


--
======================================================================
SUMMARY  This optional section especifies quantities to be written to
-- the summary file to be read by GRAF
--
======================================================================

RUNSUM

INCLUDE
  SUMMARY.INC /


--
======================================================================
SCHEDULE Specifies the production system
```

```
--
========================================================================

--Maximum timestep of 1 is required to ensure the injection starts at
--quickly enough after the condition is verified. This ensures a lower
--deltaP at the injector BHP

TUNING
  1*   1   0.1 /
/
/

RPTSCHED
  PRESSURE  SOIL  SWAT  SGAS /


WELSPECS
--Define injection and production wells
  I   G   1    1   1*   GAS /
  P   G   31   1   1*   OIL /
/


COMPDAT
--Defines well completion
--Well      K1  K2   State  Sat       Diam
  I   2*   1   10   OPEN   1   1*   0.3 /
  P   2*   1   10   OPEN   1   1*   0.3 /
/


WCONPROD
  P   OPEN   BHP   60   1*   450   1*   1*   2000 /
/

WCONINJE
  I   GAS   OPEN   BHP   1*   1*   5200 /
/

WELLSTRE
  'CO2'   1.0   0   0   0   0 /
/

WINJGAS
  I   WV   P   CO2 /
/
```

```
WECON
  P   2*   0.   2*   'CON' /
/

WELOPEN
  I   STOP /
/

-- Start the injection when the injector BHP
ACTIONW
  START_INJ   I   WBHP   <   5200   1   0 /

WCONINJE
  I   GAS   OPEN   BHP   1*   1*   5200 /
/

ENDACTIO


-- reports during 20 years
TSTEP
  366 /


TUNING
  3* /
/
/

TSTEP
  19*366 /



-- Stop Production
WELLSHUT
  P /
  I /
/


SAVE
END
```

APPENDIX 2

ECLIPSE *.DATA FILE FOR THE ALTERNATIVE CASE

```
--
======================================================================
--
--    THESIS:
--    PERFORMANCE OF EOR-CO2 MISCIBLE PROCESS USING A CONCEPTUAL MODEL
--    December 2012
--    Martin Saint-Felix
--    Base Case Aquifer Scenario *.DATA file
--
--
======================================================================
--
--Begin Amarile Project Manager Criteria. Please do not edit.
--Parent=BC2_HandP
--End Amarile Project Manager Criteria
MEMORY
100 10 /

--
======================================================================
RUNSPEC This section is mandatory and it is used to set up the
--      especification for the simulation run.
--
======================================================================

FIELD

DIMENS
--Nx   Ny   Nz
  31   16   10 /

WELLDIMS
  2   10   2   2 /

ACTDIMS
  5   2*   5 /

COMPS
```

```
--Use 5 components
  5 /

START
  1 JAN 2012 /

TABDIMS
--Determines the # of pressure and saturation tables and the maximum #
of rows
  1   1   40   40 /

WATER

AIM
--AIM solution method, avoids time step restrictions

EOS
--Peng-Robinson equation of state to be used
  PR /


NSTACK
  200 /

MULTSAVE
--Overwrite the save at each state
  0 /

--formatting of the output files
UNIFOUT
UNIFOUTS


--======================================================================
GRID    This section is mandatory and it is used to input the grid
--      or cells to be ussed into teh simulation model.
--======================================================================
-- MODEL 25*25*36 EACH BLOK 32FT (PERMEABILITY AND POROSITY
DISTRIBUTION)

EQUALS

--VALUE  X    X    Y    Y    Z    Z
  DX     32   1    31   1    16   1    10  /
  DY     32   1    31   1    16   1    10  /
  DZ     10   1    31   1    16   1    10  /
```

```
/

TOPS
  496*11453
/

INCLUDE
  ACTNUM.INC /

--Define Local Grid

PORO
  4960*0.2
/

PERMX
  496*180
  496*30
  496*500
  496*250
  496*10
  496*275
  496*150
  496*70
  496*310
  496*30
/

COPY
  PERMX   PERMY /
  PERMX   PERMZ /
/

MULTIPLY
  PERMZ   0.1 /
/


INCLUDE
  MULTIPLY.INC /


--=================================================================
PROPS   This section is mandatory and it is used to incorporate the
--      fluid and reservoir properties
--=================================================================
```

```
--You will use an entirely different fluid file in this include
statement, this is not
-- given here

INCLUDE
  PVT_1.PVO /


SWFN
--Water saturation functions (you may change these and use Kr as a
function of IFT - See Miscible key
--word and Eclipse manual
--SWAT   KRW      PCOW
  0.2    0.000    32
  0.24   0.003    21
  0.28   0.010    15.5
  0.32   0.023    12
  0.36   0.040    9.2
  0.4    0.063    7
  0.44   0.090    5.3
  0.48   0.123    4.2
  0.52   0.160    3.4
  0.56   0.203    2.7
  0.6    0.250    2.1
  0.64   0.303    1.7
  0.68   0.360    1.3
  0.72   0.423    1
  0.76   0.490    0.7
  0.8    0.563    0.5
  0.84   0.640    0.4
  0.88   0.723    0.3
  0.92   0.810    0.2
  0.96   0.903    0.1
  1      1.000    0
/

SGFN
--Gas saturation functions(you may change these)
--SGAS   KRG      PCOG
  0      0        0
  0.05   0.000    0.1
  0.1    0.004    0.2
  0.15   0.015    0.3
  0.2    0.033    0.4
  0.25   0.059    0.5
  0.3    0.093    0.6
```

```
  0.35   0.133   0.7
  0.4    0.181   0.8
  0.45   0.237   0.9
  0.5    0.300   1
  0.55   0.370   1.1
  0.6    0.448   1.2
  0.65   0.533   1.3
  0.7    0.626   1.4
  0.75   0.726   1.5
  0.8    0.834   1.6
/

SOF3
--Oil saturation functions(you may change these)
--SOIL   KRO     PC
  0      0       0.000
  0.3    0.000   0.000
  0.33   0.005   0.005
  0.36   0.018   0.018
  0.39   0.038   0.038
  0.42   0.064   0.064
  0.45   0.096   0.096
  0.48   0.133   0.133
  0.51   0.175   0.175
  0.54   0.223   0.223
  0.57   0.275   0.275
  0.6    0.333   0.333
  0.63   0.395   0.395
  0.66   0.462   0.462
  0.69   0.533   0.533
  0.72   0.609   0.609
  0.75   0.690   0.690
  0.78   0.775   0.775
  0.8    0.834   0.834
/

ROCKOPTS
/

ROCK
--Reference Pressure and Rock compressibility
  6017   4e-6 /

PVTW
--Pref   Bw    Cw          Uw
  6017   1.0   0.000003   0.31   0.0 /
```

```
DENSITY
--Surface density of water
  1*   63.0   1* /


--
======================================================================
SOLUTION This section is mandatory
--
======================================================================
--Defines the initial solution into the reservoir, adjust according to
selected pressure


EQUIL
--FT      PRES   WOC    Pc    GOC   (you may change these)
  11453   6017   11553 /

OUTSOL
--Solution output for GRAF (you may change these and add more
performance indicators)
  PRESSURE  SOIL  SWAT  SGAS  XMF  YMF  ZMF /

RPTSOL
--Output to the initial solution to the print files (you may change
these)
  PRESSURE  SOIL  SWAT  SGAS /


--
======================================================================
SUMMARY  This optional section especifies quantities to be written to
-- the summary file to be read by GRAF
--
======================================================================

RUNSUM

INCLUDE
  SUMMARY.INC /


--
======================================================================
SCHEDULE Specifies the production system
```

```
--
======================================================================

--Maximum timestep of 1 is required to ensure the injection starts at
--quickly enough after the condition is verified. This ensures a lower
--deltaP at the injector BHP

TUNING
  1*   1   0.1 /
/
/

RPTSCHED
  PRESSURE  SOIL  SWAT  SGAS /


WELSPECS
--Define injection and production wells
  I   G   1    1   1*   GAS /
  P   G   31   1   1*   OIL /
/


COMPDAT
--Defines well completion
--Well      K1  K2   State  Sat      Diam
  I   2*   1   10   OPEN   1   1*   0.3 /
  P   2*   1   10   OPEN   1   1*   0.3 /
/

WCONPROD
  P   OPEN   ORAT   60   1*   450   1*   1*   2000 /
/

WCONINJE
  I   GAS   OPEN   GRUP   2*   6018 /
/

GCONINJE
  FIELD   GAS   REIN   2*   1.0 /
/

WELLSTRE
  'CO2'   1.0   0   0   0   0 /
/
```

```
--WINJGAS
--  I   WV   P /
--/

GINJGAS
  FIELD   GV   FIELD /
/

WECON
  P   2*   0.   2*   'CON' /
/


-- Start the CO2 injection when reaching the desired field pressure
ACTIONX
  STRT_INJ   1 /
  FPR   <   5000 /
/

GCONINJE
  FIELD   GAS   RATE   260 /
/

GINJGAS
  FIELD  GV   FIELD   'CO2' /
/

ENDACTIO


-- Increase the injector Gas Rate cap if the make-up gas import is too
low
ACTIONX
  GRAT_INC   10000000 /
  FAMR        >    0     AND /
  FAMR        <    195   AND /
  FGIRT       <    800   AND /
  WSTAT   I   !=   3.0   AND /
  WSTAT   I   !=   4.0 /
/

GTADD
  FIELD   GINJ   5 /
/

ENDACTIO
```

```
-- Decrease the injector Gas Rate cap if the make-up gas import is too
high
ACTIONX
  GRAT_DEC   10000000 /
  FAMR         >    205   AND /
  WSTAT   I   !=   3.0   AND /
  WSTAT   I   !=   4.0 /
/

GTADD
  FIELD   GINJ   -5 /
/

ENDACTIO


-- reports during 20 years
TSTEP
  366 /


TUNING
  3* /
/
/

TSTEP
  19*366 /


-- Stop Production
WELLSHUT
  P /
  I /
/


SAVE
END
```

APPENDIX 3

ECLIPSE ACTNUM.INC FILE

This INCLUDE file defines the active cells of the model.

```
ACTNUM
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0


1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
```

```
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
```

```
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
```

```
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0
0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0
0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
/
```

APPENDIX 4

ECLIPSE MULTIPLY.INC FILE

This file is used to set the properties of the border cells that have to be modified, as defined in II.2.3.

```
MULTIPLY
--      Prop  Fact  Xmin  Xmax  Ymin  Ymax  Zmin  Zmax
        PORO  0.125 1     1     1     1     1     10    /
        PORO  0.125 31    31    1     1     1     10    /
        PORO  0.25  16    16    16    16    1     10    /
        PORO  0.5   2     30    1     1     1     10    /
        PORO  0.5   2     2     2     2     1     10    /
        PORO  0.5   3     3     3     3     1     10    /
        PORO  0.5   4     4     4     4     1     10    /
        PORO  0.5   5     5     5     5     1     10    /
        PORO  0.5   6     6     6     6     1     10    /
        PORO  0.5   7     7     7     7     1     10    /
        PORO  0.5   8     8     8     8     1     10    /
        PORO  0.5   9     9     9     9     1     10    /
        PORO  0.5   10    10    10    10    1     10    /
        PORO  0.5   11    11    11    11    1     10    /
        PORO  0.5   12    12    12    12    1     10    /
        PORO  0.5   13    13    13    13    1     10    /
        PORO  0.5   14    14    14    14    1     10    /
        PORO  0.5   15    15    15    15    1     10    /
        PORO  0.5   17    17    15    15    1     10    /
        PORO  0.5   18    18    14    14    1     10    /
        PORO  0.5   19    19    13    13    1     10    /
        PORO  0.5   20    20    12    12    1     10    /
        PORO  0.5   21    21    11    11    1     10    /
        PORO  0.5   22    22    10    10    1     10    /
        PORO  0.5   23    23    9     9     1     10    /
        PORO  0.5   24    24    8     8     1     10    /
        PORO  0.5   25    25    7     7     1     10    /
        PORO  0.5   26    26    6     6     1     10    /
        PORO  0.5   27    27    5     5     1     10    /
        PORO  0.5   28    28    4     4     1     10    /
        PORO  0.5   29    29    3     3     1     10    /
        PORO  0.5   30    30    2     2     1     10    /
```

```
      PERMX 0.5   1     31    1     1     1     10    /
      PERMX 0.5   16    16    16    16    1     10    /

      PERMY 0.5   1     1     1     1     1     10    /
      PERMY 0.5   31    31    1     1     1     10    /

/
```

APPENDIX 5

ECLIPSE PVT_1.PVO FILE

This file contains the PVT data of the reservoir fluid.

```
ECHO
-- Units: F
RTEMP
--
-- Constant Reservoir Temperature
--
         158
/

EOS
--
-- Equation of State (Reservoir EoS)
--
   PR3
/

NCOMPS
--
-- Number of Components
--
       5
/
PRCORR
--
-- Modified Peng-Robinson EoS
--
CNAMES
--
-- Component Names
--
   'CO2'
   'N2C1'
   'C2C4'
   'C5C6'
   'C7+'
/
```

```
MW
--
-- Molecular Weights (Reservoir EoS)
--
         44.01
   16.08289335
   43.36888092
   78.94285856
        265.35
/

OMEGAA
--
-- EoS Omega-a Coefficient (Reservoir EoS)
--
   0.457235529
   0.328930834672046
   0.328930834672046
   0.284889689911773
   0.284889689911773
/

OMEGAB
--
-- EoS Omega-b Coefficient (Reservoir EoS)
--
   0.077796074
   0.0692438988364954
   0.0692438988364954
   0.0616186300327335
   0.0616186300327335
/

-- Units: R
TCRIT
--
-- Critical Temperatures (Reservoir EoS)
--
   548.459999999228
   342.693664378282
   592.350442157288
   1065.09619335861
   1090.0470179634
/

-- Units: psia
```

```
PCRIT
--
-- Critical Pressures (Reservoir EoS)
--
   1071.33110996644
   667.196896579098
   578.512808318354
   510.152398300812
   357.866762628131
/

-- Units: ft3 /lb-mole
VCRIT
--
-- Critical Volumes (Reservoir EoS)
--
   1.50573518513559
   1.56938193481649
   3.19552369156483
   5.3364523715559
   16.2959605162247
/

ZCRIT
--
-- Critical Z-Factors (Reservoir EoS)
--
   0.274077797373613
   0.284723353881409
   0.290819017557039
   0.238182712751346
   0.498542970026143
/

SSHIFT
--
-- EoS Volume Shift (Reservoir EoS)
--
   -0.0991359185150855
   -0.121939419505631
   -0.110107520137807
   -0.0437364617740838
   -1.29966946853132
/

ACF
```

```
--
-- Acentric Factors (Reservoir EoS)
--
   0.0793434294582521
   0.00461601911758701
   0.025671998229909
   0.191638782245778
   0.891335017793224
/

BIC
--
-- Binary Interaction Coefficients (Reservoir EoS)
--
     0.1
     0.1       0
 0.101775327197493       0       0
 0.101775327197493       0       0       0
/

PARACHOR
--
-- Component Parachors
--
            78
      76.88002
   146.0459542
   252.3349876
   681.1968845
/

-- Units: ft3 /lb-mole
VCRITVIS
--
-- Critical Volumes for Viscosity Calc (Reservoir EoS)
--
   1.3872152036497
   1.30391733952975
   2.65499344511537
   4.98516685601047
   15.2232375694788
/

ZCRITVIS
--
-- Critical Z-Factors for Viscosity Calculation (Reservoir EoS)
```

```
--
   0.252504485020226
   0.23656173800576
   0.241626306000168
   0.222503731432438
   0.46572511413152
/

LBCCOEF
--
-- Lorentz-Bray-Clark Viscosity Correlation Coefficients
--
   0.0998603703795769 0.0577106974327623 8.91486574020177e-005 -
0.00410723842285606 0.00448366944294375
/
--PVTi--Please do not alter these lines
--PVTi--as PVTi can use them to re-create the fluid model
--PVTiMODSPEC
========================================================
--PVTiTITLE
--PVTiModified System: From Automatically created during keyword export
--PVTiVERSION
--PVTi  2006.1  /
--PVTiNCOMPS
--PVTi        5 /
--PVTiEOS
--PVTi PR3  /
--PVTiPRCORR
--PVTiLBC
--PVTiOPTIONS
--PVTi  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  1  0  0  0
--PVTi/
--PVTiNOECHO
--PVTiMODSYS
========================================================
--PVTiUNITS
--PVTi   FIELD       ABSOL         PERCENT      /
--PVTiDEGREES
--PVTi   Fahrenheit /
--PVTiSTCOND
--PVTi      60.0000      14.6959 /
--PVTiCNAMES
--PVTi CO2
--PVTi N2C1
--PVTi C2C4
--PVTi C5C6
```

```
--PVTi C7+
--PVTi /
--PVTiTCRIT
--PVTi  8.878998547E+01 -1.169763447E+02  1.326804265E+02
6.054261651E+02
--PVTi  6.303769891E+02
/
--PVTiPCRIT
--PVTi  1.071331110E+03  6.671968966E+02  5.785128083E+02
5.101523983E+02
--PVTi  3.578667626E+02
/
--PVTiVCRIT
--PVTi  1.505735240E+00  1.569381992E+00  3.195523808E+00
5.336452566E+00
--PVTi  1.629596111E+01
/
--PVTiZCRIT
--PVTi  2.740777974E-01  2.847233539E-01  2.908190176E-01
2.381827128E-01
--PVTi  4.985429700E-01
/
--PVTiVCRITVIS
--PVTi  1.387215254E+00  1.303917387E+00  2.654993542E+00
4.985167038E+00
--PVTi  1.522323812E+01
/
--PVTiZCRITVIS
--PVTi  2.525044850E-01  2.365617380E-01  2.416263060E-01
2.225037314E-01
--PVTi  4.657251141E-01
/
--PVTiLBCCOEF
--PVTi  9.986037038E-02  5.771069743E-02  8.914865740E-05 -
4.107238423E-03
--PVTi  4.483669443E-03
/
--PVTiSSHIFT
--PVTi -9.913591852E-02 -1.219394195E-01 -1.101075201E-01 -
4.373646177E-02
--PVTi -1.299669469E+00
/
--PVTiACF
--PVTi  7.934342946E-02  4.616019118E-03  2.567119982E-02
1.916387822E-01
```

```
--PVTi  8.913350178E-01
/
--PVTiMW
--PVTi  4.401000000E+01  1.608289335E+01  4.336888092E+01
7.894285856E+01
--PVTi  2.653500000E+02
/
--PVTiOMEGAA
--PVTi     0.457236     0.328931     0.328931     0.284890     0.284890
/
--PVTiOMEGAB
--PVTi     0.077796     0.069244     0.069244     0.061619     0.061619
/
--PVTiZI
--PVTi  6.000000000E-02  6.001000000E+01  6.550000000E+00
4.030000000E+00
--PVTi  2.935000000E+01
/
--PVTiTBOIL
--PVTi -1.092100093E+02 -2.589951711E+02 -5.379501839E+01
1.215135826E+02
--PVTi  6.864373275E+02
/
--PVTiTREF
--PVTi  6.772998603E+01 -2.588115717E+02 -4.069871339E+01
6.360293899E+01
--PVTi  5.999998631E+01
/
--PVTiDREF
--PVTi  4.850653269E+01  2.661074144E+01  3.531542638E+01
4.108705365E+01
--PVTi  5.631002894E+01
/
--PVTiPARACHOR
--PVTi  7.800000000E+01  7.688002000E+01  1.460459542E+02
2.523349876E+02
--PVTi  6.811968845E+02
/
--PVTiHYDRO
--PVTi  N N H H H
--PVTi /
--PVTiBIC
--PVTi   1.000000000E-01
--PVTi   1.000000000E-01  0.000000000E+00
--PVTi   1.017753272E-01  0.000000000E+00  0.000000000E+00
```

```
--PVTi   1.017753272E-01  0.000000000E+00  0.000000000E+00
0.000000000E+00
--PVTi /
--PVTiSAMPLES
--PVTiCO2
--PVTi  1.000000000E+02  0.000000000E+00  0.000000000E+00
0.000000000E+00
--PVTi  0.000000000E+00
/
--PVTi /
--PVTiSAMTITLE
--PVTi /
--PVTiSPECHA
--PVTi  8.289864000E+01  8.076194873E+01  5.516019511E+00 -
2.454694867E+01
--PVTi  7.069714544E+00
/
--PVTiSPECHB
--PVTi  3.074785920E-01  2.172993991E-01  1.166306329E+00
2.291958211E+00
--PVTi  3.410367305E+00
/
--PVTiSPECHC
--PVTi -2.345445360E-04  5.032292899E-05 -5.286032515E-04 -
1.228433093E-03
--PVTi -7.757471318E-04
/
--PVTiSPECHD
--PVTi  7.180362000E-08 -4.739959932E-08  8.029606759E-08
2.559423046E-07
--PVTi  0.000000000E+00
/
--PVTiHEATVAPS
--PVTi  1.802570424E+04  0.000000000E+00  3.394477054E+04
6.379121162E+04
--PVTi  2.217694729E+05
/
--PVTiCALVAL
--PVTi  0.000000000E+00  1.884735590E+03  4.680089557E+03
8.435282288E+03
--PVTi  2.792697363E+04
/
--PVTi--End of PVTi generated section--
ZI
--
-- Overall Composition
```

```
--
        0.0006
        0.6001
        0.0655
        0.0403
        0.2935
/
```

APPENDIX 6

ECLIPSE SUMMARY.INC FILE

This file defines the outputs of an ECLIPSE run. It is used to yield the same outputs from all the models.

```
-- Field data:
FPR     Field Pressure average value

-- Oil Production:
FOPR    Field Oil Production Rate
FOPT    Field Oil Production Total
FOIP    Field Oil In Place
FOIPL   Field Oil In Place (Liquid phase)
FOIPG   Field Oil In Place (Gas phase)
FOE     Field (OIP(initial) - OIP(now)) / OIP(initial)
FOSAT   Field Oil SATuration average value
FOMT    Field Oil Mass Total
WOPRT   Wells Oil Production Rate Target / Limit
/
WGPRT   Wells Gas Production Rate Target / Limit
/

-- Gas Production / Injection:
FGPR    Field Gas Production Rate
FGPT    Field Gas Production Total
FGIR    Field Gas Injection Rate
WGIR    Well Gas Injection Rate
/
FGIRT   Field Gas Injection Rate Target / Limit
WGIRT   Well Gas Injection Rate Target / Limit
/
FGIT    Field Gas Injection Total
FGOR    Field Gas-Oil Ratio
FGSAT   Field Gas SATuration average value
FGMT    Field Gas Mass Total
FMUF    Field Make-Up Fraction (at reinjecting wells)
FAMR    Field Make-Up gas Rate (at source of reinjection gas)
FAMT    Field Make-Up gas Total (at source of reinjection gas)
```

```
-- Water Production / Injection:
FWPR    Field Water Production Rate
FWPT    Field Water Production Total
FWIR    Field Water Injection Rate
FWIT    Field Water Injection Total
FWCT    Field Water Cut
FWSAT   Field Water SATuration average value

-- Fluid Properties:
FODN    Field Oil Density at Surface Conditions
FGDN    Field Gas Density at Surface Conditions

-- Wells info:
WBHP    Wells Bottom Hole Pressure
/
WTHP    Wells Tubing Head Pressure
/
WPI     Wells Productivity Index of well's preferred phase
/
WMCTL   Wells Mode of ConTroL
/

-- Component info:
FXMF    Field Liquid Mole Fraction
1 /
FXMF
2 /
FXMF
3 /
FXMF
4 /
FXMF
5 /
FYMF    Field Vapor Mole Fraction
1 /
FYMF
2 /
FYMF
3 /
FYMF
4 /
FYMF
5 /
FCMIP   Field Component Hydrocarbon as Moles
1 /
```

```
FCMIP
2 /
FCMIP
3 /
FCMIP
4 /
FCMIP
5 /
FCMIR   Field Hydrocarbon Component Molar Injection Rates
1 /
FCMIR
2 /
FCMIR
3 /
FCMIR
4 /
FCMIR
5 /
FCMIT   Field Hydrocarbon Component Molar Injection Totals
1 /
FCMIT
2 /
FCMIT
3 /
FCMIT
4 /
FCMIT
5 /
FCMPR   Field Hydrocarbon Component Molar Production Rates
1 /
FCMPR
2 /
FCMPR
3 /
FCMPR
4 /
FCMPR
5 /
FCMPT   Field Hydrocarbon Component Molar Production Totals
1 /
FCMPT
2 /
FCMPT
3 /
FCMPT
4 /
```

```
FCMPT
5 /
FCOMT   Hydrocarbon component molar totals in the oil phase
1 /
FCOMT
2 /
FCOMT
3 /
FCOMT
4 /
FCOMT
5 /
FCOMR   Hydrocarbon component molar rates in the oil phase
1 /
FCOMR
2 /
FCOMR
3 /
FCOMR
4 /
FCOMR
5 /
FCGMT   Hydrocarbon component molar totals in the gas phase
1 /
FCGMT
2 /
FCGMT
3 /
FCGMT
4 /
FCGMT
5 /
FCGMR   Hydrocarbon component molar rates in the gas phase
1 /
FCGMR
2 /
FCGMR
3 /
FCGMR
4 /
FCGMR
5 /
```

APPENDIX 7

SCREENING CRITERIA FOR THE REFERENCE CASE

For all the following tables, the values in the first row are the values of the maximum gas rate in Mscf/day, the values in the first column are the values of the maximum oil rate in STB/day.

Plateau Duration (years):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	9.3	11.2	12.8	14.3	15.7	16.8	17.8	18.7	19.4	20.0	20.0	20.0	20.0	20.0
30	5.5	8.6	10.0	10.9	12.0	12.9	13.8	14.5	15.2	15.9	16.4	16.9	17.2	17.6
35	3.7	5.6	7.8	8.5	9.3	10.1	10.9	11.6	12.1	12.7	13.2	13.7	14.1	14.4
40	2.6	4.0	6.2	6.8	7.4	8.0	8.7	9.3	9.8	10.3	10.8	11.2	11.7	12.1
45	2.1	3.1	4.3	5.9	6.4	6.8	7.3	7.8	8.3	8.7	9.1	9.4	9.8	10.1
50	1.7	2.3	3.1	4.6	5.4	5.8	6.2	6.6	7.0	7.3	7.6	8.0	8.3	8.6
55	1.5	1.9	2.6	3.3	4.6	4.9	5.3	5.6	5.9	6.4	6.6	6.9	7.2	7.5
60	1.3	1.6	2.2	2.7	3.7	4.3	4.6	5.0	5.2	5.5	5.8	6.1	6.3	6.5
65	1.1	1.4	1.7	2.3	2.7	3.7	4.0	4.2	4.5	4.8	5.0	5.3	5.5	5.7
70	1.0	1.2	1.5	1.9	2.3	2.9	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1
75	0.9	1.1	1.3	1.5	2.0	2.4	3.1	3.4	3.6	3.8	4.0	4.2	4.4	4.6
80	0.8	1.0	1.2	1.4	1.8	2.0	2.6	3.0	3.2	3.4	3.6	3.8	4.0	4.1
85	0.7	0.9	1.0	1.2	1.5	1.7	2.0	2.7	2.9	3.1	3.3	3.4	3.5	3.7

Plateau Duration (0 to 1):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	0.76	0.63	0.51	0.41	0.31	0.23	0.16	0.09	0.04	0.00	0.00	0.00	0.00	0.00
30	1.00	0.81	0.72	0.65	0.58	0.51	0.45	0.39	0.34	0.30	0.26	0.23	0.20	0.17
35	1.00	1.00	0.87	0.82	0.76	0.71	0.65	0.60	0.56	0.52	0.49	0.45	0.43	0.40
40	0.00	1.00	0.99	0.94	0.90	0.86	0.81	0.77	0.73	0.69	0.66	0.63	0.60	0.56
45	0.00	1.00	1.00	1.00	0.97	0.94	0.91	0.87	0.84	0.81	0.78	0.76	0.73	0.71
50	0.00	0.00	1.00	1.00	1.00	1.00	0.99	0.96	0.93	0.91	0.89	0.86	0.84	0.81
55	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	0.97	0.95	0.93	0.91	0.90
60	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.96
65	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
70	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
75	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00
85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00	1.00

Total Oil Production (STB):

	150	**200**	**250**	**300**	**350**	**400**	**450**	**500**	**550**	**600**	**650**	**700**	**750**	**800**
25	146,733	157,638	165,397	171,211	175,507	178,577	180,706	182,081	182,762	182,998	183,000	183,000	183,000	183,000
30	153,304	167,343	177,068	184,697	191,065	196,079	200,123	203,458	206,394	208,681	210,620	212,248	213,716	214,827
35	156,002	172,666	183,692	192,635	200,017	206,075	211,117	215,384	219,148	222,386	225,142	227,623	229,753	231,693
40	157,654	174,754	187,088	196,824	205,178	212,169	218,041	223,095	227,401	231,165	234,394	237,253	239,683	241,814
45	159,539	177,908	191,735	201,914	210,216	217,178	223,116	228,169	232,590	236,450	239,763	242,601	245,297	247,545
50	159,378	178,334	192,809	204,105	212,717	219,963	226,088	231,437	235,986	239,988	243,452	246,389	249,033	251,427
55	160,814	179,858	194,635	206,336	215,379	222,829	229,106	234,546	239,203	243,248	246,670	249,688	252,255	254,554
60	161,034	180,354	195,565	207,542	217,177	224,839	231,236	236,756	241,471	245,466	248,869	251,908	254,552	256,861
65	161,125	180,017	195,145	207,435	217,537	225,590	232,352	238,106	242,936	247,123	250,595	253,649	256,379	258,696
70	162,089	181,674	197,029	209,308	219,301	227,540	234,107	239,680	244,357	248,437	251,859	254,819	257,499	259,694
75	162,071	181,573	197,063	209,538	219,697	228,091	234,919	240,647	245,402	249,511	253,054	256,088	258,644	260,869
80	161,854	181,553	197,261	209,836	220,122	228,632	235,666	241,513	246,389	250,385	253,934	256,946	259,623	261,802
85	161,738	181,049	196,499	209,946	220,201	228,357	235,653	241,962	246,736	251,123	254,691	257,473	260,231	262,591

Total Oil Production (0 to 1):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	0.56	0.60	0.63	0.65	0.67	0.68	0.69	0.69	0.70	0.70	0.70	0.70	0.70	0.70
30	0.58	0.64	0.67	0.70	0.73	0.75	0.76	0.77	0.79	0.79	0.80	0.81	0.81	0.82
35	0.59	0.66	0.70	0.73	0.76	0.78	0.80	0.82	0.83	0.85	0.86	0.87	0.87	0.88
40	0.60	0.67	0.71	0.75	0.78	0.81	0.83	0.85	0.87	0.88	0.89	0.90	0.91	0.92
45	0.61	0.68	0.73	0.77	0.80	0.83	0.85	0.87	0.89	0.90	0.91	0.92	0.93	0.94
50	0.61	0.68	0.73	0.78	0.81	0.84	0.86	0.88	0.90	0.91	0.93	0.94	0.95	0.96
55	0.61	0.68	0.74	0.79	0.82	0.85	0.87	0.89	0.91	0.93	0.94	0.95	0.96	0.97
60	0.61	0.69	0.74	0.79	0.83	0.86	0.88	0.90	0.92	0.93	0.95	0.96	0.97	0.98
65	0.61	0.69	0.74	0.79	0.83	0.86	0.88	0.91	0.93	0.94	0.95	0.97	0.98	0.99
70	0.62	0.69	0.75	0.80	0.84	0.87	0.89	0.91	0.93	0.95	0.96	0.97	0.98	0.99
75	0.62	0.69	0.75	0.80	0.84	0.87	0.89	0.92	0.93	0.95	0.96	0.98	0.98	0.99
80	0.62	0.69	0.75	0.80	0.84	0.87	0.90	0.92	0.94	0.95	0.97	0.98	0.99	1.00
85	0.62	0.69	0.75	0.80	0.84	0.87	0.90	0.92	0.94	0.96	0.97	0.98	0.99	1.00

Total Gas Imported (Mscf):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	484,423	514,363	535,635	551,384	562,930	571,112	576,739	580,535	582,338	582,875	582,870	582,870	582,870	582,870
30	503,442	541,722	567,823	588,324	605,272	618,850	629,953	639,085	647,178	653,494	658,683	663,176	667,149	670,299
35	511,064	556,515	586,041	610,044	629,820	646,357	660,202	672,024	682,426	691,476	699,275	706,336	712,452	718,014
40	517,703	564,455	597,700	623,932	646,196	665,188	681,232	695,065	707,088	717,625	726,857	735,002	742,212	748,622
45	522,566	572,546	609,559	636,881	659,229	678,265	694,685	708,849	721,344	732,324	741,981	750,483	758,542	765,527
50	522,964	574,846	613,816	644,308	667,632	687,495	704,501	719,589	732,507	744,090	754,284	763,245	771,415	778,904
55	526,350	578,256	618,012	649,497	673,931	694,310	711,771	727,113	740,427	752,256	762,459	771,709	779,814	787,221
60	527,618	580,293	621,250	653,550	679,616	700,605	718,430	734,044	747,574	759,317	769,685	779,093	787,502	795,125
65	527,555	579,339	620,315	653,514	680,760	702,734	721,349	737,563	751,441	763,751	774,340	783,920	792,599	800,375
70	529,374	582,723	624,157	657,371	684,498	707,134	725,507	741,354	754,980	767,116	777,647	787,124	795,788	803,362
75	529,853	582,914	624,695	658,446	686,041	709,127	728,227	744,532	758,396	770,693	781,584	791,228	799,734	807,385
80	527,077	580,661	622,978	657,002	684,976	708,457	728,173	744,854	760,808	771,204	782,147	791,899	802,394	808,377
85	526,974	579,576	621,348	656,297	684,702	709,244	728,508	745,297	759,782	774,313	785,372	793,190	803,475	811,084

Total Gas Imported (0 to 1):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	0.60	0.63	0.66	0.68	0.69	0.70	0.71	0.72	0.72	0.72	0.72	0.72	0.72	0.72
30	0.62	0.67	0.70	0.73	0.75	0.76	0.78	0.79	0.80	0.81	0.81	0.82	0.82	0.83
35	0.63	0.69	0.72	0.75	0.78	0.80	0.81	0.83	0.84	0.85	0.86	0.87	0.88	0.89
40	0.64	0.70	0.74	0.77	0.80	0.82	0.84	0.86	0.87	0.88	0.90	0.91	0.92	0.92
45	0.64	0.71	0.75	0.79	0.81	0.84	0.86	0.87	0.89	0.90	0.91	0.93	0.94	0.94
50	0.64	0.71	0.76	0.79	0.82	0.85	0.87	0.89	0.90	0.92	0.93	0.94	0.95	0.96
55	0.65	0.71	0.76	0.80	0.83	0.86	0.88	0.90	0.91	0.93	0.94	0.95	0.96	0.97
60	0.65	0.72	0.77	0.81	0.84	0.86	0.89	0.91	0.92	0.94	0.95	0.96	0.97	0.98
65	0.65	0.71	0.76	0.81	0.84	0.87	0.89	0.91	0.93	0.94	0.95	0.97	0.98	0.99
70	0.65	0.72	0.77	0.81	0.84	0.87	0.89	0.91	0.93	0.95	0.96	0.97	0.98	0.99
75	0.65	0.72	0.77	0.81	0.85	0.87	0.90	0.92	0.94	0.95	0.96	0.98	0.99	1.00
80	0.65	0.72	0.77	0.81	0.84	0.87	0.90	0.92	0.94	0.95	0.96	0.98	0.99	1.00
85	0.65	0.71	0.77	0.81	0.84	0.87	0.90	0.92	0.94	0.95	0.97	0.98	0.99	1.00

Gas-Oil Ratio at the end of the Oil Production Plateau (Mscf/STB):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	6.00	8.00	10.00	12.00	14.00	16.00	18.00	20.00	22.00	24.00	26.00	28.00	30.00	32.00
30	5.00	6.67	8.33	10.00	11.67	13.33	15.00	16.67	18.33	20.00	21.67	23.33	25.00	26.67
35	4.29	5.71	7.14	8.57	10.00	11.43	12.86	14.29	15.71	17.14	18.57	20.00	21.43	22.86
40	3.75	5.00	6.25	7.50	8.75	10.00	11.25	12.50	13.75	15.00	16.25	17.50	18.75	20.00
45	3.33	4.44	5.56	6.67	7.78	8.89	10.00	11.11	12.22	13.33	14.44	15.56	16.67	17.78
50	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00	11.00	12.00	13.00	14.00	15.00	16.00
55	2.73	3.64	4.55	5.45	6.36	7.27	8.18	9.09	10.00	10.91	11.82	12.73	13.64	14.55
60	2.50	3.33	4.17	5.00	5.83	6.67	7.50	8.33	9.17	10.00	10.83	11.67	12.50	13.33
65	2.31	3.08	3.85	4.62	5.38	6.15	6.92	7.69	8.46	9.23	10.00	10.77	11.54	12.31
70	2.14	2.86	3.57	4.29	5.00	5.71	6.43	7.14	7.86	8.57	9.29	10.00	10.71	11.43
75	2.00	2.67	3.33	4.00	4.67	5.33	6.00	6.67	7.33	8.00	8.67	9.33	10.00	10.67
80	1.88	2.50	3.13	3.75	4.38	5.00	5.63	6.25	6.88	7.50	8.13	8.75	9.38	10.00
85	1.76	2.35	2.94	3.53	4.12	4.71	5.29	5.88	6.47	7.06	7.65	8.24	8.82	9.41

Gas-Oil Ratio at the end of the Oil Production Plateau (0 to 1):

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	0.86	0.79	0.73	0.66	0.60	0.53	0.46	0.40	0.33	0.26	0.20	0.13	0.07	0.00
30	0.89	0.84	0.78	0.73	0.67	0.62	0.56	0.51	0.45	0.40	0.34	0.29	0.23	0.18
35	0.92	0.87	0.82	0.77	0.73	0.68	0.63	0.59	0.54	0.49	0.44	0.40	0.35	0.30
40	0.93	0.89	0.85	0.81	0.77	0.73	0.69	0.64	0.60	0.56	0.52	0.48	0.44	0.40
45	0.95	0.91	0.87	0.84	0.80	0.76	0.73	0.69	0.65	0.62	0.58	0.54	0.51	0.47
50	0.96	0.93	0.89	0.86	0.83	0.79	0.76	0.73	0.69	0.66	0.63	0.60	0.56	0.53
55	0.97	0.94	0.91	0.88	0.85	0.82	0.79	0.76	0.73	0.70	0.67	0.64	0.61	0.58
60	0.98	0.95	0.92	0.89	0.87	0.84	0.81	0.78	0.76	0.73	0.70	0.67	0.64	0.62
65	0.98	0.96	0.93	0.91	0.88	0.85	0.83	0.80	0.78	0.75	0.73	0.70	0.68	0.65
70	0.99	0.96	0.94	0.92	0.89	0.87	0.85	0.82	0.80	0.77	0.75	0.73	0.70	0.68
75	0.99	0.97	0.95	0.93	0.90	0.88	0.86	0.84	0.82	0.79	0.77	0.75	0.73	0.71
80	1.00	0.98	0.96	0.93	0.91	0.89	0.87	0.85	0.83	0.81	0.79	0.77	0.75	0.73
85	1.00	0.98	0.96	0.94	0.92	0.90	0.88	0.86	0.84	0.82	0.81	0.79	0.77	0.75

All criteria combined and scaled from 0 to 1:

	150	200	250	300	350	400	450	500	550	600	650	700	750	800
25	0.46	0.38	0.30	0.22	0.15	0.10	0.06	0.03	0.01	0.00	0.00	0.00	0.00	0.00
30	0.66	0.54	0.47	0.42	0.35	0.29	0.24	0.19	0.15	0.12	0.09	0.07	0.05	0.03
35	0.69	0.72	0.63	0.59	0.53	0.47	0.42	0.36	0.32	0.27	0.23	0.19	0.16	0.13
40	0.00	0.75	0.75	0.72	0.68	0.63	0.58	0.53	0.48	0.43	0.38	0.34	0.30	0.26
45	0.00	0.78	0.81	0.82	0.78	0.75	0.70	0.66	0.61	0.56	0.52	0.48	0.43	0.39
50	0.00	0.00	0.83	0.85	0.85	0.84	0.81	0.77	0.73	0.69	0.65	0.60	0.56	0.52
55	0.00	0.00	0.00	0.87	0.88	0.88	0.87	0.86	0.84	0.79	0.75	0.71	0.67	0.63
60	0.00	0.00	0.00	0.00	0.91	0.91	0.90	0.89	0.88	0.86	0.84	0.81	0.77	0.73
65	0.00	0.00	0.00	0.00	0.00	0.93	0.93	0.92	0.91	0.90	0.88	0.86	0.84	0.81
70	0.00	0.00	0.00	0.00	0.00	0.00	0.96	0.95	0.94	0.93	0.91	0.90	0.88	0.85
75	0.00	0.00	0.00	0.00	0.00	0.00	0.98	0.97	0.97	0.96	0.94	0.93	0.91	0.89
80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.99	0.98	0.97	0.95	0.94	0.92
85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.99	0.98	0.96	0.95

APPENDIX 8

SCREENING CRITERIA FOR THE ALTERNATIVE CASES

For all the following tables, the values in the first row are the values of the injection trigger pressure in psi, the values in the first column are the values of the import CO_2 plateau rate.

Import CO_2 plateau duration (years):

	3000	**3500**	**4000**	**4500**	**5000**
100	16.3	18.2	18.5	18.8	18.5
150	11.0	11.5	11.7	11.7	11.4
200	7.8	8.1	8.2	7.8	7.6
250	5.9	6.0	5.9	5.4	5.5
300	4.5	4.5	4.3	3.9	3.5

Import CO_2 plateau duration (0 to 1):

	3000	**3500**	**4000**	**4500**	**5000**
100	1.00	1.00	1.00	1.00	1.00
150	1.00	1.00	1.00	1.00	1.00
200	1.00	1.00	1.00	1.00	1.00
250	0.84	0.86	0.84	0.78	0.78
300	0.65	0.65	0.62	0.55	0.50

Oil production plateau duration (years):

	3000	**3500**	**4000**	**4500**	**5000**
100	0.8	0.8	0.8	0.9	1.0
150	0.8	0.8	0.8	1.1	2.2
200	1.1	1.2	1.4	2.7	4.1
250	1.4	2.2	2.1	4.2	4.6
300	1.9	2.6	3.5	4.2	4.5

Oil production plateau duration (0 to 1):

	3000	3500	4000	4500	5000
100	0.00	0.00	0.00	0.00	0.00
150	0.00	0.00	0.00	0.00	0.00
200	0.00	0.00	0.00	1.00	1.00
250	0.00	0.00	0.00	1.00	1.00
300	0.00	1.00	1.00	1.00	1.00

Total oil production (STB):

	3000	3500	4000	4500	5000
100	159,958	172,016	177,096	178,106	184,143
150	175,986	190,087	194,211	196,690	207,090
200	186,616	204,383	207,957	215,520	219,637
250	190,802	212,465	217,243	222,589	225,067
300	196,428	217,232	219,678	223,524	226,982

Total oil production (0 to 1):

	3000	3500	4000	4500	5000
100	0.70	0.76	0.78	0.78	0.81
150	0.78	0.84	0.86	0.87	0.91
200	0.82	0.90	0.92	0.95	0.97
250	0.84	0.94	0.96	0.98	0.99
300	0.87	0.96	0.97	0.98	1.00

Total CO_2 imported (Mscf):

	3000	3500	4000	4500	5000
100	596,200	670,036	685,612	682,032	684,254
150	682,677	718,717	726,198	721,082	729,970
200	711,966	757,896	763,526	761,472	767,638
250	724,666	777,155	785,283	778,969	786,443
300	738,410	788,817	788,975	783,690	785,840

Total CO_2 imported (0 to 1):

	3000	3500	4000	4500	5000
100	0.23	0.40	0.48	0.51	0.64
150	0.30	0.57	0.67	0.77	0.92
200	0.37	0.68	0.80	0.94	0.98
250	0.38	0.75	0.87	0.96	1.00
300	0.40	0.79	0.88	0.93	0.96

PV10 ($):

	3000	3500	4000	4500	5000
100	$189,143,326	$335,650,718	$395,680,529	$424,889,424	$532,755,218
150	$252,576,653	$468,782,212	$553,354,886	$637,734,446	$762,697,621
200	$304,320,294	$564,908,795	$661,497,007	$778,020,573	$815,131,058
250	$318,405,019	$622,810,673	$720,561,454	$799,596,707	$829,287,722
300	$335,533,031	$653,397,865	$726,896,228	$771,802,563	$799,266,851

PV10 (0 to 1):

	3000	3500	4000	4500	5000
100	0.23	0.40	0.48	0.51	0.64
150	0.30	0.57	0.67	0.77	0.92
200	0.37	0.68	0.80	0.94	0.98
250	0.38	0.75	0.87	0.96	1.00
300	0.40	0.79	0.88	0.93	0.96

IRR (%):

	3000	3500	4000	4500	5000
100	20.5%	28.4%	31.9%	34.1%	40.6%
150	22.5%	33.0%	38.4%	44.3%	51.2%
200	23.6%	36.0%	42.8%	49.8%	51.2%
250	23.8%	37.7%	44.8%	48.6%	48.2%
300	23.9%	38.1%	44.7%	45.7%	44.6%

IRR (0 to 1):

	3000	3500	4000	4500	5000
100	0.26	0.45	0.53	0.58	0.74
150	0.30	0.56	0.69	0.83	1.00
200	0.33	0.63	0.80	0.96	1.00
250	0.34	0.67	0.84	0.94	0.93
300	0.34	0.68	0.84	0.87	0.84